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

February 15, 2013

Public Utility Commission of Oregon
Attn: Filing Center
550 Capitol Street, N.E., Suite 215
Salem, OR 97301-2551

RE: **Advice No. 13-03, Portland General Electric General Rate Revision UE 262**

PGE hereby submits for filing revised tariff sheets implementing a general rate revision. A list of the revised Tariff sheets is attached.

Enclosed are 30 copies including 10 courtesy copies of Direct Testimony, Exhibits and an Executive Summary that conforms to the requirements in OAR 860-022-0019 for a general rate revision. Three copies of the non-confidential portion of work papers are provided on the enclosed CDs showing the source and calculation of rates. Confidential work papers accompany our filing pursuant to Protective Order 13-042. By April 1st, we will file the remaining power cost updates.

The tariff changes are filed with an effective date of March 17, 2013, subject to suspension for investigation. We request that a prehearing conference be held expeditiously to establish a schedule that will allow a Commission Order by mid-December and revised prices effective January 1, 2014.

<u>All Data Request Responses</u>

Per the advanced approval of OPUC Management, PGE is posting its responses to all Data Requests, on an external website: https://pgn.huddle.net. The PGE administrator of the Huddle website is Mary Widman (503) 464-8223 or mary.widman@pgn.com. We have a list of OPUC Staff members who will be working on the upcoming rate case and we are sending each of them an invitation to Huddle so they may have timely access to the standard data responses, posted with this submitted filing.

Please direct your communications related to this filing to the following email address: pge.opuc.filings@pgn.com

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Sincerely,

Randall J. Dahlgren
Director, Regulatory Policy & Affairs

Enclosures
cc: Service List – UE 215 (Electronic only)

Advice No. 13-03
Portland General Electric General Rate Revision
Revised Tariff Sheets filed February 15, 2013

Eleventh Revision of Sheet No. 1-1
Fourteenth Revision of Sheet No. 1-2
Twentieth Revision of Sheet No. 1-3
Ninth Revision of Sheet No. 1-4
Sixth Revision of Sheet No. 7-1
Fourth Revision of Sheet No. 15-1
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Sixth Revision of Sheet No. 38-3
Fifth Revision of Sheet No. 47-1
Sixth Revision of Sheet No. 49-1
Eighth Revision of Sheet No. 75-1
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Fourth Revision of Sheet No. 81-1
Seventh Revision of Sheet No. 83-1
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The following sheet is **withdrawn:**

Fourth Revision of Sheet No. 93-1

Schedule 93, is being withdrawn in its entirety.

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SCHEDULE 7
RESIDENTIAL SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Residential Customers.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge			
Single Phase Service	$10.00		(I)
Three Phase Service	$10.00		(R)
Transmission and Related Services Charge	0.299	¢ per kWh	(I)
Distribution Charge	3.962	¢ per kWh	(I)
Energy Charge Options			
Standard Service			
First 1,000 kWh	6.434	¢ per kWh	(R)
Over 1,000 kWh	7.156	¢ per kWh	
or			
Time-of-Use (TOU) Portfolio (Whole Premises or Electric Vehicle (EV) TOU) (Enrollment is necessary)			
On-Peak Period	12.739	¢ per kWh	
Mid-Peak Period	7.156	¢ per kWh	
Off-Peak Period	4.247	¢ per kWh	(R)
First 1,000 kWh block adjustment**	(0.722)	¢ per kWh	

* See Schedule 100 for applicable adjustments.
** Not applicable to separately metered Electric Vehicle (EV) TOU option.

SCHEDULE 15
OUTDOOR AREA LIGHTING
STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Customers for outdoor area lighting.

CHARACTER OF SERVICE

Lighting services, which consist of the provision of Company-owned luminaires mounted on Company-owned poles, in accordance with Company specifications as to equipment, installation, maintenance and operation.

The Company will replace lamps on a scheduled basis. Subject to the Company's operating schedules and requirements, the Company will replace individual burned-out lamps as soon as reasonably possible after the Customer notifies the Company of the burn-out.

MONTHLY RATE

Included in the service rates for each installed luminaire are the following pricing components:

Transmission and Related Services Charge	0.182	¢ per kWh	**(R)**
Distribution Charge	4.682	¢ per kWh	**(I)**
Cost of Service Energy Charge	5.078	¢ per kWh	**(R)**

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)

Rates for Area Lighting

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate [1] Per Luminaire	
Cobrahead					
Mercury Vapor	175	7,000	66	$12.78 [2]	(I)
	400	21,000	147	21.10 [2]	(R)
	1,000	55,000	374	44.46 [2]	(I)
HPS	70	6,300	30	9.32 [2]	
	100	9,500	43	10.56	
	150	16,000	62	12.47	
	200	22,000	79	14.32	
	250	29,000	102	16.76	
	310	37,000	124	19.34 [2]	
	400	50,000	163	23.21	
Flood, HPS	100	9,500	43	10.59 [2]	
	200	22,000	79	15.22 [2]	
	250	29,000	102	17.55	
	400	50,000	163	23.60	
Shoebox, HPS (bronze color, flat lens or drop lens, multi-volt)	70	6,300	30	10.77	
	100	9,500	43	12.25	
	150	16,500	62	14.44	
Special Acorn Type, HPS	100	9,500	43	15.23	
HADCO Victorian, HPS	150	16,500	62	17.12	
	200	22,000	79	19.58	
	250	29,000	102	21.89	
Early American Post-Top, HPS Black	100	9,500	43	11.33	(I)

(1) See Schedule 100 for applicable adjustments.
(2) No new service.

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)
Rates for Area Lighting (Continued)

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate Per Luminaire(1)	
Special Types					
Cobrahead, Metal Halide	150	10,000	60	$12.90	(R)
	175	12,000	71	14.28	(I)
Flood, Metal Halide	350	30,000	139	22.65	
	400	40,000	156	23.13	
Flood, HPS	750	105,000	285	39.26	
HADCO Independence, HPS	100	9,500	43	15.36	
	150	16,000	62	16.91	
HADCO Capitol Acorn, HPS	100	9,500	43	19.34	
	150	16,000	62	21.28	
	200	22,000	79	22.84	
	250	29,000	102	25.14	
HADCO Techtra, HPS	100	9,500	43	24.48	
	150	16,000	62	26.02	(I)
	250	29,000	102	29.35	(R)
HADCO Westbrooke, HPS	70	6,300	30	16.99	(I)
	100	9,500	43	18.04	
	150	16,000	62	19.94	
	200	22,000	79	21.92	
	250	29,000	102	24.09	
KIM Archetype, HPS	250	29,000	102	27.08	
	400	50,000	163	27.95	
Holophane Mongoose, HPS	150	16,000	62	17.60	
	250	29,000	102	20.88	(I)
					(D)

(1) See Schedule 100 for applicable adjustments.
(2) No new service.

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)

Type of Pole Rates for Area Light Poles[1]	Pole Length (feet)	Monthly Rate Per Pole	
Wood, Standard	35 or less	$7.40	(I)
	40 to 55	9.70	(C)
Wood, Painted for Underground	35 or less	7.40 [2]	
Wood, Curved Laminated	30 or less	9.19 [2]	
Aluminum, Regular	16	8.86	
	25	14.70	
	30	15.89	
	35	19.02	
Aluminum, Fluted Ornamental	14	12.99	
Aluminum Davit	25	13.60	
	30	14.60	
	35	15.97	
	40	21.68	
Aluminum Double Davit	30	21.58	(I)
Aluminum, HADCO, Fluted Ornamental	16	13.28	(R)
Aluminum, HADCO, Non-fluted Techtra Ornamental	18	25.57	(I)
Concrete Ameron Post-Top	25	25.51	(R)
Fiberglass Fluted Ornamental; Black	14	15.70	(I)
Fiberglass, Regular			
Black	20	6.51	
Gray or Bronze	30	11.07	
Other Colors (as available)	35	9.53	
Fiberglass, Anchor Base Gray	35	17.45	
Fiberglass, Direct Bury with Shroud	18	10.50	(I)

(1) No pole charge for luminaires placed on existing Company-owned distribution poles.
(2) No new service.

SCHEDULE 32
SMALL NONRESIDENTIAL
STANDARD SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Small Nonresidential Customers. A Small Nonresidential Customer is a Customer that has not exceeded 30 kW more than once within the preceding 13 months, or with seven months or less of service has not exceeded 30 kW.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge			
Single Phase Service	$14.00		(I)
Three Phase Service	$18.00		
Transmission and Related Services Charge	0.248	¢ per kWh	
Distribution Charge			
First 5,000 kWh	4.401	¢ per kWh	
Over 5,000 kWh	0.833	¢ per kWh	(I)
Energy Charge Options			
Standard Service	6.024	¢ per kWh	(R)
or			
Time-of-Use (TOU) Portfolio (enrollment is necessary)			
On-Peak Period	10.644	¢ per kWh	
Mid-Peak Period	6.024	¢ per kWh	
Off-Peak Period	3.550	¢ per kWh	(R)

* See Schedule 100 for applicable adjustments.

SCHEDULE 32 (Continued)

DAILY PRICE

The Daily Price, applicable with Direct Access Service, is available to those Customers who were served under Schedule 532 and subsequently returned to this schedule before meeting the minimum term requirement of Schedule 532. The Customer will be charged the Daily Price charge of this schedule until the term requirement of Schedule 532 is met.

The Daily Price will consist of:

- the Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Firm Index)
- plus 0.294 ¢ per kWh for wheeling (I)
- times a loss adjustment factor of 1.0820

If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported.

Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

PLUG-IN ELECTRIC VEHICLE (EV) TOU OPTION

A small Nonresidential Customer wishing to charge EV's may do so either as part of an integrated service (Standard service or TOU service) or as a separately metered service billed under the TOU option. In such cases, the applicable Basic, Transmission and Related Services, and Distribution charges will apply to the separately metered service as will all other adjustments applied to this schedule. Renewable Portfolio Options are also available under this EV option.

If the Customer chooses separately metered service for EV charging, the service shall be used for the sole and exclusive purpose of all EV charging. The Customer, at its expense, will install all necessary and required equipment to accommodate the second metered service at the premises. Such service must be metered with a network meter as defined in Rule B (30) for the purpose of load research, and to collect and analyze data to characterize electric vehicle use in diverse geographic dynamics and evaluate the effectiveness of the charging station infrastructure.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 38
LARGE NONRESIDENTIAL OPTIONAL TIME-OF-DAY STANDARD SERVICE (COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

This optional schedule is applicable to Large Nonresidential Customers: 1) served at Secondary voltage with a monthly Demand that does not exceed 200 kW more than once in the preceding 13 months; or 2) who were receiving service on Schedule 38 as of December 31, 2006.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge			
Single Phase Service	$25.00		(I)
Three Phase Service	$25.00		
Transmission and Related Services Charge	0.235	¢ per kWh	(I)
Distribution Charge	6.323	¢ per kWh	(I)
Energy Charge*			
On-Peak Period	6.462	¢ per kWh	(R)
Off-Peak Period	5.462	¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.

** On-peak Period is Monday-Friday, 7:00 a.m. to 8:00 p.m. off-peak Period is Monday-Friday, 8:00 p.m. to 7:00 a.m.; and all day Saturday and Sunday.

MINIMUM CHARGE

The Minimum Charge will be the Basic Charge. In Addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge if necessary, to justify the Company's investment in service facilities.

REACTIVE DEMAND

In addition to the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

SCHEDULE 38 (Continued)

DIRECT ACCESS DEFAULT SERVICE

A Customer returning to Schedule 38 service before completing the term of service specified in Schedule 538, must be billed at the Daily Price for the remainder of the term. This provision does not eliminate the requirement to receive service on Schedule 81 when notice is insufficient. The Daily Price under this schedule is as follows:

Daily Price Option - The Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Firm Index) plus 0.294¢ per kWh for wheeling, plus losses. If prices (I) are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported. To begin service under this option, the Customer will notify the Company by the close of the November Election Window or for eligible Customers, the close of a Balance-of-Year Election Window.

Losses will be included by multiplying the above applicable Energy Charge Option by the following adjustment factors:

Secondary Delivery Voltage	1.0820

PLUG-IN ELECTRIC VEHICLE (EV) TIME OF DAY OPTION

A large Nonresidential Customer wishing to charge EV's may do so either as part of an integrated service or as a separately metered service billed under the TOU Option. In such cases, the applicable Basic, Transmission and Related Services, and Distribution charges will apply to the separately metered service as will all other adjustments applied to this schedule.

If the Customer chooses separately metered service for EV charging, the service shall be used for the sole and exclusive purpose of all EV charging. The Customer, at its expense, will install all necessary and required equipment to accommodate the second metered service at the premises. Such service must be metered with a network meter as defined in Rule B (30) for the purpose of load research, and to collect and analyze data to characterize electric vehicle use in diverse geographic dynamics and evaluate the effectiveness of the charging station infrastructure.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 47
SMALL NONRESIDENTIAL
IRRIGATION AND DRAINAGE PUMPING
STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Small Nonresidential Customers for irrigation and drainage pumping; may include other incidental service if an additional meter would otherwise be required. A Small Nonresidential Customer is a Customer that has not exceeded 30 kW more than once within the preceding 13 months, or with seven months or less of service has not exceeded 30 kW.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge			
Summer Months**	$30.00		(I)
Winter Months**	No Charge		
Transmission and Related Services Charge	0.391	¢ per kWh	
Distribution Charge			
First 50 kWh per kW of Demand***	6.598	¢ per kWh	
Over 50 kWh per kW of Demand	4.598	¢ per kWh	
Energy Charge	7.399	¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.
** Summer Months and Winter Months commence with meter readings as defined in Rule B.
*** For billing purposes, the Demand will not be less than 10 kW.

MINIMUM CHARGE

The Minimum Charge will be the Basic Charge. In addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge if necessary, to justify the Company's investment in service facilities.

SCHEDULE 49
LARGE NONRESIDENTIAL
IRRIGATION AND DRAINAGE PUMPING
STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers for irrigation and drainage pumping; may include other incidental service if an additional meter would otherwise be required. A Large Nonresidential Customer is defined as having a monthly Demand exceeding 30 kW at least twice within the preceding 13 months, or with seven months or less of service having exceeding 30 kW once.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge			
Summer Months**	$35.00		(I)
Winter Months**	No Charge		
Transmission and Related Services Charge	0.382	¢ per kWh	
Distribution Charge			
First 50 kWh per kW of Demand***	4.443	¢ per kWh	
Over 50 kWh per kW of Demand	2.443	¢ per kWh	
Energy Charge	7.233	¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.
** Summer Months and Winter Months commence with meter readings as defined in Rule B.
*** For billing purposes, the Demand will not be less than 30 kW.

MINIMUM CHARGE

The Minimum Charge will be the Basic Charge. In addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge if necessary, to justify the Company's investment in service facilities.

SCHEDULE 75
PARTIAL REQUIREMENTS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers supplying all or some portion of their load by self-generation operating on a regular basis, where the self-generation has a total nameplate rating of 2 MW or greater. A Large Nonresidential Customer is a Customer that has exceeded 30 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 30 kW.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Point of Delivery (POD)*:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge	$4,850.00	$4,460.00	$5,130.00	(I)
Transmission and Related Services Charge				
per kW of monthly On-Peak Demand	$0.88	$0.85	$0.84	
Distribution Charges				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.90	$1.85	$1.85	
Over 4,000 kW	$1.26	$1.21	$1.21	
per kW of monthly On-Peak Demand	$2.05	$1.99	$1.12	(I)
Generation Contingency Reserves Charges				
Spinning Reserves				
per kW of Reserved Capacity > 2,000 kW	$0.234	$0.234	$0.234	
Supplemental Reserves				
per kW of Reserved Capacity > 2,000 kW	$0.234	$0.234	$0.234	
System Usage Charge				
per kWh	0.162 ¢	0.157 ¢	0.154 ¢	(R)
Energy Charge				
per kWh	See Energy Charge Below			

* See Schedule 100 for applicable adjustments.

SCHEDULE 75 (Continued)

ENERGY CHARGE (Continued)

Baseline Energy (Continued)

If other than the typical operations are used to determine Baseline Energy, the Customer and the Company must agree on the Baseline Energy before the Customer may take service under this schedule. The Company may require use of an alternate method to determine the Baseline Energy when the Customer's usage not normally supplied by its generator is highly variable.

Baseline Energy will be charged at the applicable Energy Charge, including adjustments, under Schedule 89. All Energy Charge options included in Schedule 89 are available to the Customer on Schedule 75 based on the terms and conditions under Schedule 89. For Energy supplied in excess of Baseline Energy, the Scheduled Maintenance Energy and/or Unscheduled Energy charges will apply except for Energy supplied pursuant to Schedule 76R.

Any Energy Charge option for Baseline Energy selected by a Customer will remain in effect and continue to be the default option until the Customer has given the required notice to change the applicable Energy Charge Option. To change options, Customers must give notice as specified for that option and must complete the specified term of their current option. The Cost of Service Option will be the default for Customers or new Customers who have not selected another option or Direct Access Service.

Scheduled Maintenance Energy

Scheduled Maintenance Energy is Energy prescheduled for delivery, up to 744 hours per calendar year, to serve the Customer's load normally served by the Customer's own generation (i.e. above Baseline Energy). Scheduled Maintenance must be prescheduled at least one month (30 days) before delivery for a time period mutually agreeable to the Company and the Customer.

When the Customer preschedules Energy for an entire calendar month, the Customer may choose that the Scheduled Maintenance Energy Charge be either the Monthly Fixed or Daily Price Energy Charge Option, including adjustments as identified in Schedule 100 and notice requirements as described under Schedule 89. When the Customer preschedules Energy for less than an entire month, the Scheduled Maintenance Energy will be charged at the Daily Price Energy Option, including adjustments, under Schedule 89.

Unscheduled Energy

Any Electricity provided to the Customer that does not qualify as Baseline Energy or Scheduled Maintenance Energy will be Unscheduled Energy and priced at an Hourly Rate consisting of the Dow Jones Mid-Columbia Hourly Firm Electricity Price Index (DJ-Mid-C Hourly Firm Index) plus 0.294¢ per kWh for wheeling, a 0.300¢ per kWh recovery factor, (I)
plus losses.

SCHEDULE 76R
PARTIAL REQUIREMENTS
ECONOMIC REPLACEMENT POWER RIDER

PURPOSE

To provide Customers served on Schedule 75 with the option of purchasing Energy from the Company to replace some, or all, of the Customer's on-site generation when the Customer deems it is more economically beneficial than self generating.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers served on Schedule 75.

MONTHY RATE

The following charges are in addition to applicable charges under Schedule 75:*

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Transmission and Related Services Charge per kW of Daily Economic Replacement Power (ERP) On-Peak Demand per day	$0.034	$0.033	$0.033	(I)
Daily ERP Demand Charge per kW of Daily ERP Demand during On-Peak hours per day**	$0.080	$0.078	$0.044	(I)
System Usage Charge per kWh of ERP	0.162 ¢	0.157 ¢	0.154 ¢	(R)
Transaction Fee per Energy Needs Forecast (ENF)	$50.00	$50.00	$50.00	
Energy Charge* per kWh of ERP	See below for ERP Pricing			

* See Schedule 100 for applicable adjustments.

** Peak hours (also called heavy load hours "HLH") are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours (also called light load hours "LLH") are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

SCHEDULE 76R (Continued)

ENF AND ERP (Continued)
ERP Supply Options (Continued)
ENF Options for ERP (Continued)

The Daily ENF pre-scheduling protocols will conform to the standard practices, applicable definitions, requirements and schedules of the WECC. Pre-Schedule Day means the trading day immediately preceding the day of delivery consistent with WECC practices for Saturday, Sunday, Monday or holiday deliveries.

ERP Pricing

The following ERP Energy Charges are applied to the applicable hourly ENF and summed for the hours for the monthly billing:

Short-Notice ERP: The Short Notice ERP Energy Charge will be an Hourly Rate consisting of the Dow Jones Mid-Columbia Hourly Price Index (DJ-Mid-C Hourly Index) plus a 5% adder, which will not be less than 0.15¢ per kWh, plus 0.294¢ per kWh for wheeling, plus losses. If prices are not reported for a particular hour or hours, the average of the immediately preceding and following reported hours' prices within on- or off-peak periods, as applicable, will determine the price for the non-reported period. Prices reported with no transaction volume or as survey-based will be considered reported. (I)

Daily ERP: The Daily ERP Energy Charge will be determined in accordance with a commodity energy price quote from the Company accepted by the Customer plus a 5% adder, which will not be less than 0.15¢ per kWh, plus 0.294¢ per kWh for wheeling, plus losses. Customer will communicate with PGE between hour 0615 and 0625 to receive the PGE commodity energy price quote based on the customer's submitted ENF for the day of delivery. Customer will state acceptance of quote within 5 minutes of receipt of quote from the Company. The quote may incorporate reasonable premiums to reflect the additional cost of ENF amounts that are in nonstandard block sizes (i.e., other than multiples of 25 MW) and such premium will not be separately stated. The methods to communicate and the times to receive information and quotes may be adjusted with mutual written agreement of the parties. Failure to accept a quote in the stated time is deemed to mean the quote is rejected and the transaction will not take place. (I)

Monthly ERP: The Monthly ERP Energy Charge will be determined in accordance with a price quote accepted by the Customer plus a 5% adder, which will not be less than 0.15¢ per kWh, plus 0.294¢ per kWh for wheeling, plus losses. At customer request and based on the submitted Monthly ENF, the Company will provide a price quote for the next full calendar month for the ENF commodity energy only amount specified by the customer at the time of the request. The Company will respond to the request with a quote within 4 hours or as otherwise mutually agreed to. Customer will accept or reject the quote within 30 minutes. Customer communication regarding a price quote will be in the manner agreed to by the Company and the Customer. The quote may incorporate reasonable premiums to reflect the additional cost of ENF amounts that are in nonstandard block sizes (i.e., other than multiples of 25 MW) and such premium will not be separately stated. (I)

SCHEDULE 76R (Continued)

ENF AND ERP (Continued)
ERP Supply Options (Continued)
ERP Pricing (Continued)

The methods to communicate and the times to receive information and quotes may be adjusted with mutual written agreement of the parties. Failure to accept a quote in the stated time is deemed to mean the quote is rejected and the transaction will not take place.

On-peak hours (Heavy Load Hours, HLH) are between 6:00 a.m. and 10:00 p.m. PPT (hours ending 0700 through 2200), Monday through Saturday. Off-peak hours (Light Load Hours, LLH) are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all hours Sunday.

Losses will be included by multiplying the ERP Charge by the following adjustment factors:

Subtransmission Delivery Voltage	1.0337
Primary Delivery Voltage	1.0482
Secondary Delivery Voltage	1.0820

ACTUAL ENERGY USAGE

Actual Energy usage during times when ERP deliveries are occurring will be the amount of Energy above the Customer's Schedule 75 Baseline Energy.

IMBALANCE ENERGY SETTLEMENT

Imbalance Settlement Amounts are bill credits or charges resulting from hourly Imbalance Energy multiplied by the applicable hourly Settlement Price and summed for all hours in the billing period. Imbalance Energy is the kWh amount determined hourly as the deviation between Actual Energy for such hour and the ENF for such hour (i.e., Imbalance Energy = Actual Energy less ENF).

For any Imbalance Energy in any hour up to 7.5% of the hourly ENF (positive or negative amount), the Imbalance Settlement Amount for the hour is:

- For positive Imbalance Energy (where Customer receives more ERP than the ENF), the Imbalance Energy multiplied by the Settlement Price of the Dow Jones Mid-Columbia Hourly Price Index (DJ-Mid-C Hourly Index), plus 0.294¢ per kWh for wheeling, plus losses. (I)
- For negative Imbalance Energy (where Customer receives less ERP than the ENF), the Imbalance Energy is multiplied by the Settlement Price of the DJ-Mid-C Hourly Index plus 0.294¢ per kWh for wheeling, plus losses. (I)

SCHEDULE 76R (Continued)

IMBALANCE ENERGY SETTLEMENT (Continued)

For any Imbalance Energy in any hour in excess of 7.5% of the hourly ENF (positive or negative amount), the Imbalance Settlement Amount for the hour is:

- For positive excess Imbalance Energy, the excess Imbalance Energy multiplied by the Settlement Price, which is the Dow Jones Mid-Columbia Hourly Price Index (DJ-Mid-C Hourly Index), plus 10%, plus 0.294¢ per kWh for wheeling, plus losses. **(I)**
- For negative excess Imbalance Energy, the excess Energy Imbalance is multiplied by the Settlement Price of the DJ-Mid-C Hourly Index, less 10%, plus 0.294¢ per kWh for wheeling, **(I)** plus losses.

The Imbalance Settlement Amount may be a credit or charge in any hour.

DAILY ERP DEMAND

Daily ERP Demand is the highest 30 minute Demand occurring during the days that the Company supplies ERP to the Customer less the sum of the Customer's Schedule 75 Baseline Demand and any Unscheduled Demand. Daily ERP Demand will not be less than zero. Daily ERP Demand will be billed for each day in the month that the Company supplies ERP to the Customer.

If the sum of the Customer's Unscheduled and Schedule 75 Baseline Demand exceeds their Daily ERP Demand, no additional Daily Demand charges are applied to the service under this schedule for the applicable Billing Period.

UNSCHEDULED DEMAND

Unscheduled Demand is the difference in the highest 30 minute monthly Demand and the Customer's Baseline occurring when the Customer did not receive ERP.

ADJUSTMENTS

Service under this rider is subject to all adjustments as summarized in Schedule 100, except for: 1) any power cost adjustment recovery based on costs incurred while the Customer is taking Service under this schedule, and 2) Schedule 128.

SPECIAL CONDITIONS

1. Prior to receiving service under this schedule, the Customer and the Company must enter into a written agreement governing the terms and conditions of service.

2. Service under this schedule applies only to prescheduled ERP supplied by the Company pursuant to this schedule and the corresponding agreement. All other Energy supplied will be made under the terms of Schedule 75. All notice provisions of this schedule and agreement must be complied with for delivery of Energy. The Customer is required to maintain Schedule 75 service unless otherwise agreed to by the Company.

SCHEDULE 81
NONRESIDENTIAL
EMERGENCY DEFAULT SERVICE

AVAILABLE

In all territory served by the Company. The Company may restrict Customer loads returning to this schedule in accordance with Rule N Curtailment Plan and Rule C (Section 2).

APPLICABLE

To existing Nonresidential Customers who are no longer receiving Direct Access Service and have not provided the Company with the notice required to receive service under the applicable Standard Service rate schedule.

MONTHLY RATE

All charges for Emergency Default Service except the energy charge will be billed at the Customer's applicable Standard Service rate schedule for five business days after the Customer's initial purchase of Emergency Default Service.

ENERGY CHARGE DAILY RATE

The Energy Charge Daily Rate will be 125% of the Dow Jones Mid-Columbia Daily on- and off-peak Firm Electricity Price Index (DJ-Mid-C Firm Index) plus 0.294¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on-peak and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported. (I)

Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

Losses will be included by multiplying the Energy Charge Daily Rate by the following adjustment factors:

Subtransmission Delivery Voltage	1.0337
Primary Delivery Voltage	1.0482
Secondary Delivery Voltage	1.0820

REACTIVE DEMAND CHARGE

In addition to the charges as specified in the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

SCHEDULE 83
LARGE NONRESIDENTIAL
STANDARD SERVICE
(31 – 200 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customers whose Demand has not exceeded 200 kW more than six times in the preceding 13 months and has not exceeded 1,000 kW more than once in the preceding 13 months, or with seven months or less of service has not had a Demand exceeding 1,000 kW. Service under this Schedule is available for Secondary Delivery Voltage only.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge		
Single Phase Service	$30.00	(I)
Three Phase Service	$40.00	
Transmission and Related Services Charge		
per kW of monthly On-Peak Demand	$0.88	(C)
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 30 kW	$2.98	
Over 30 kW	$2.48	
per kW of monthly Demand	$2.05	(I)
Energy Charge ***		
Cost of Service Option per kWh On-Peak Period	6.178 ¢	(C)(R)
See below for Daily Pricing Option description Off-Peak Period	5.478 ¢	(N)
System Usage Charge		
per kWh	0.849 ¢	(I)

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the applicable POD.

*** Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday. (N)
(N)

SCHEDULE 83 (Continued)

MONTHLY RATE (Continued)

Energy Charge Options:

Any Energy Charge option selected by a Customer will remain in effect and continue to be the default option until the Customer has given the required notice to change the applicable Energy Charge Option. To change options, Customers must give notice as specified for that option below and must complete the specified term of their current option. The Cost of Service Option will be the default for Customers or new Customers who have not selected another option or Direct Access Service. If a Customer chooses Direct Access Service or a pricing option other than the Cost of Service Option, that Customer may not receive service under the Cost of Service Option until the next service year and with timely notice.

NON COST OF SERVICE OPTION

Daily Price Option - The Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Firm Index) plus 0.294¢ per kWh for wheeling, plus losses. If prices **(I)** are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported. To begin service under this option, the Customer receiving service under Cost of Service price option will notify the Company by the close of the November Election Window or for eligible Customers, the close of a Balance-of-Year Election Window.

Losses will be included by multiplying the above applicable Energy Charge Option by the following adjustment factors:

Secondary Delivery Voltage	1.0820

Non-Cost of Service Option is subject to Schedule 128, Short Term Transition Adjustment.

Interval metering and meter communications should be in place prior to initiation of service under this schedule. Where interval metering has not been installed, the Customer's Electricity usage will be billed as 65% on-peak and 35% off-peak. Upon installation of an interval meter, the Company will bill the Customer according to actual metered usage.

PLUG-IN ELECTRIC VEHICLE TIME OF USE (EV TOU) OPTION

Should a Customer receiving service under this Schedule 83 opt for a separately metered EV TOU option, the separately metered Electric Vehicle charging load will determine the applicable rate schedule under which EV TOU charging service is provided. For example, please refer to Schedules 32 and 38.

SCHEDULE 85
LARGE NONRESIDENTIAL
STANDARD SERVICE
(201 – 4,000 kW) (C)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Secondary Delivery Voltage Large Nonresidential Customer whose Demand has exceeded 200 kW more than six times in the preceding 13 months but has not exceeded 4,000 kW more than (C) once in the preceding 13 months, or with seven months or less of service has not had a Demand exceeding 4,000 kW. To each Primary Delivery Voltage Large Nonresidential Customer whose (C) Demand has not exceeded 4,000 kW more than once in the preceding 13 months, or with seven (C) months or less of service has not had a Demand exceeding 4,000 kW. (C)

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Point of Delivery (POD)*:

	Delivery Voltage		
	Secondary	Primary	
Basic Charge	\$370.00	\$390.00	(I)
Transmission and Related Services Charge			
per kW of monthly On-Peak Demand	\$0.88	\$0.85	
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 200 kW	\$3.12	\$3.04	
Over 200 kW	\$2.12	\$2.04	(R)
per kW of monthly On-Peak Demand	\$2.05	\$1.99	(I)
Energy Charge			
On-Peak Period***	6.085 ¢	5.928 ¢	(R)
Off-Peak Period***	5.085 ¢	4.928 ¢	
See below for Daily Pricing Option description.			
System Usage Charge			
per kWh	0.194 ¢	0.187 ¢	(R)

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the applicable POD.

*** Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

SCHEDULE 85 (Continued)

MONTHLY RATE (Continued)

Energy Charge Options:

Any Energy Charge option selected by a Customer will remain in effect and continue to be the default option until the Customer has given the required notice to change the applicable Energy Charge Option. To change options, Customers must give notice as specified for that option below and must complete the specified term of their current option. The Cost of Service Option will be the default for Customers or new Customers who have not selected another option or Direct Access Service. If a Customer chooses Direct Access Service or a pricing option other than the Cost of Service Option, that Customer may not receive service under the Cost of Service Option until the next service year and with timely notice.

PLUG-IN ELECTRIC VEHICLE TIME OF USE (EV TOU) OPTION

Should a Customer receiving service under this Schedule 85 opt for a separately metered EV TOU option, the separately metered Electric Vehicle charging load will determine the applicable rate Schedule under which EV TOU charging service is provided. For example, please refer to Schedules 32 and 38.

NON COST OF SERVICE OPTION

Daily Price Option - The Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Firm Index) plus 0.294¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported. To begin service under this option, the Customer receiving service under Cost of Service price option will notify the Company by the close of the November Election Window or for eligible Customers, the close of a Balance-of-Year Election Window. **(I)**

Losses will be included by multiplying the above applicable Energy Charge Option by the following adjustment factors:

Primary Delivery Voltage	1.0482
Secondary Delivery Voltage	1.0820

Non-Cost of Service Option is subject to Schedule 128, Short Term Transition Adjustment.

Interval metering and meter communications should be in place prior to initiation of service under this schedule. Where interval metering has not been installed, the Customer's Electricity usage will be billed as 65% on-peak and 35% off-peak. Upon installation of an interval meter, the Company will bill the Customer according to actual metered usage.

SCHEDULE 89
LARGE NONRESIDENTIAL
STANDARD SERVICE
(>4,000kW) (C)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has exceeded 4,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 4,000 kW. (C)
(C)

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Point of Delivery (POD)*:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge	$4,850.00	$4,460.00	$5,130.00	(I)
Transmission and Related Services Charge				
per kW of monthly On-Peak Demand	$0.88	$0.85	$0.84	
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.90	$1.85	$1.85	
Over 4,000 kW	$1.26	$1.21	$1.21	
per kW of monthly On-Peak Demand	$2.05	$1.99	$1.12	(I)
Energy Charge				
On-Peak Period***	5.781 ¢	5.611 ¢	5.537 ¢	(R)
Off-Peak Period***	4.781 ¢	4.611 ¢	4.537 ¢	
See below for Daily Pricing Option description.				
System Usage Charge				
Per kWh	0.162 ¢	0.157 ¢	0.154 ¢	(R)

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the applicable POD.

*** Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

SCHEDULE 89 (Continued)

MONTHLY RATE (Continued)

Energy Charge Options:

Any Energy Charge option selected by a Customer will remain in effect and continue to be the default option until the Customer has given the required notice to change the applicable Energy Charge Option. To change options, Customers must give notice as specified for that option below and must complete the specified term of their current option. The Cost of Service Option will be the default for Customers or new Customers who have not selected another option or Direct Access Service. If a Customer chooses Direct Access Service or a pricing option other than the Cost of Service Option, it may not receive service under the Cost of Service Option until the next service year and with timely notice.

NON-COST OF SERVICE OPTION

Daily Price Option - The Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Firm Index) plus 0.294¢ per kWh for wheeling, plus losses. If prices **(I)** are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported. To begin service under this option, the Customer receiving service under Cost of Service price option will notify the Company by the close of the November Election Window or for eligible Customers, the close of a Balance-of-Year Election Window.

Losses will be included by multiplying the above applicable Energy Charge Option by the following adjustment factors:

Subtransmission Delivery Voltage	1.0337
Primary Delivery Voltage	1.0482
Secondary Delivery Voltage	1.0820

Non-Cost of Service Option is subject to Schedule 128, Short Term Transition Adjustment

PLUG-IN ELECTRIC VEHICLE TIME OF USE (EV TOU) OPTION

Should a Customer receiving service under this Schedule 89 opt for a separately metered EV TOU option, the separately metered Electric Vehicle charging load will determine the applicable rate schedule under which EV TOU charging service is provided. For example, please refer to Schedules 32 and 38.

SCHEDULE 91 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)
Option A - Luminaire (Continued)

The Customer is responsible for repair or replacement of luminaires and circuits damaged as a result of rotted wood poles owned by the Customer. **(N)** **(N)**

The Company may remove or discontinue service to any luminaire and related equipment that has become unsafe or unsatisfactory for further service by reason of deterioration, storm, flood, and lightning, proximity to interference by trees or structures, or other causes as determined by the Company. The Company will notify the Customer as soon as reasonably practical of any such service discontinuation and luminaire replacement schedule.

Option B - Luminaire

Option B provides electricity service to Customer purchased and owned luminaires at the monthly Option B rate applicable to the installed type of light.

The Company does not at any time assume ownership of Option B luminaires.

As defined herein, the Company provides for maintenance only to luminaires and related equipment at the applicable monthly Option B rate. The Company will replace non-repairable Option B luminaires for which the Customer is charged and billed the appropriate replacement costs [(1)], in addition to the applicable monthly Option B rate.

Maintenance Service under Option B

Includes preventative group lamp replacement and glassware cleaning subject to the Company's operating schedule.

Maintenance under Option B luminaires specifically does not include replacement of failed or failing ballasts or replacement of luminaires that are deemed inoperable due to general deterioration, lack of replacement parts, or replacement of parts associated with Emergency Repair that will not bring the unit into operable status. Such inoperable luminaires will be designated as non-repairable luminaires. This exclusion does not include replacements of Power Doors where the Customer is qualified and paying the applicable Cobrahead Power Door rate. In addition, maintenance under Option B luminaires excludes maintenance related to vegetation management, luminaire relocation or modification of the luminaire (such as adding light shields).

(1) Replacement costs include: Installation Labor + Material costs and loading + Removal Labor = total billable charges. For applicable labor rates, refer to page 91-8 of this Schedule.

SCHEDULE 91 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)

Option C – Luminaire

Option C provides electricity service to luminaires that are purchased, owned and maintained by the Customer and installed on Customer-owned poles. As a condition to the election of Option C, Customer is responsible for ensuring that all new underground service installations of Option C luminaires are isolated by a disconnect switch or fuse. Both the equipment used to isolate the luminaire and its location must be approved by the Company. **(C)**

Maintenance Service under Option C

The Company does not maintain Customer-purchased lighting when mounted on Customer-owned poles. Such maintenance and service is the sole responsibility of the Customer.

Special Provisions for Option B to Option C Luminaire Conversion and Future Maintenance Election

1. The Company will, with not less than 180 days written notice from the Customer (the requesting municipality) and subject to completion of all conditions necessary to finalize such election, convert the entirety of the Customer's lighting service under Option B luminaire lighting rates to the equivalent Option C luminaires lighting rates (with respect to Monthly kWh usage) including Option B luminaires attachment to Company-owned poles.

2. Upon such conversion, the Customer will assume all on-going maintenance responsibilities for the luminaires and associated circuits in accordance with this schedule's provisions for Option C luminaires. The Customer may not require that the Company provide new Option B lighting following the conversion to Option C luminaires. The Customer must notify and inform all affected residents of the conversion that all maintenance and repair services are the sole responsibility of the Customer, and not the Company.

3. The Customer may choose the Schedule 91 Option B to Schedule 95 Option C Luminaire Conversion and Future Maintenance Election as described in Schedule 95 if converting to Schedule 95 Option C luminaires and the above notice has not been given.

SCHEDULE 91 (Continued)

MONTHLY RATE

In addition to the service rates for Option A and B lights, all Customers will pay the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Transmission and Related Services Charge	0.182 ¢ per kWh	(R)
Distribution Charge	4.682 ¢ per kWh	(I)
Energy Charge		
Cost of Service Option	5.078 ¢ per kWh	(R)

Daily Price Option – Available only to Customers with an average load of five MW or greater on Schedules 91 and 95 and those customers that met the five MW or greater threshold prior to converting to lights from Schedule 91 to Schedule 95. This selection of this option applies to all luminaires served under Schedules 91 and 95. This option gives eligible Customers an option between a daily Energy price and a Cost of Service option for the Energy charge. In addition to the daily Energy price, the Customer will pay a Basic Charge of $75 per month to help offset the costs of billing this option. The daily Energy price for all kWh will be the Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Firm Index) plus 0.294¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. (I)

Prices reported with no transaction volume or as "survey-based" will be considered reported. For the purposes of calculating the daily on- and off-peak usage, actual kWhs will be determined for each month, using Sunrise Sunset Tables with adjustments for typical photocell operation and 4,100 annual burning hours.

For Customers billed on the Daily price Option, an average of the daily rates will be used to bill installations and removals that occur during the month. Any additional analysis of billing options and price comparisons beyond the monthly bill will be billed at a rate of $100 per manhour.

Losses will be included by multiplying the applicable daily Energy price by 1.0820.

The Daily Price Option is subject to Schedule 128, Short Term Transition Adjustment.

Enrollment for Service

To begin service under the Daily Price Option on January 1st, the Customer will notify the Company by 5:00 p.m. PPT on November 15th (or the following working day if the 15th falls on a weekend or holiday) of the year prior to the service year of its choice of this option. Customers selecting this option must commit to this option for an entire service year. The Customer will continue to be billed on this option until timely notice is received to return to the Cost of Service Option.

SCHEDULE 91 (Continued)

RATES FOR STANDARD LIGHTING

High-Pressure Sodium (HPS) Only – Service Rates

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
Cobrahead Power Doors **	70	6,300	30	*	$ 1.28	(R)
	100	9,500	43	*	1.29	
	150	16,000	62	*	1.30	
	200	22,000	79	*	1.36	
	250	29,000	102	*	1.37	
	400	50,000	163	*	1.39	
Cobrahead	70	6,300	30	$ 5.20	1.53	
	100	9,500	43	5.14	1.52	
	150	16,000	62	5.17	1.53	
	200	22,000	79	5.80	1.58	(I)(R)
	250	29,000	102	5.94	1.61	
	400	50,000	163	6.32	1.64	
Flood	250	29,000	102	6.73	1.70	
	400	50,000	163	6.72	1.69	
Early American Post-Top	100	9,500	43	5.92	1.60	
Shoebox (bronze color, flat lens, or drop lens, multi-volt)	70	6,300	30	6.65	1.70	
	100	9,500	43	6.83	1.72	
	150	16,000	62	7.14	1.77	(I)(R)

* Not offered.
** Service is only available to Customers with total power door luminaires in excess of 2,500.

RATES FOR STANDARD POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Fiberglass, Black	20	$ 6.51	$ 0.19	(I)
Fiberglass, Bronze	30	10.26	0.29	
Fiberglass, Gray	30	11.07	0.32	
Wood, Standard	30 to 35	7.40	0.21	
Wood, Standard	40 to 55	9.70	0.28	(I)

SCHEDULE 91 (Continued)

RATES FOR CUSTOM LIGHTING

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
Special Acorn-Types						
HPS	100	9,500	43	$ 10.27	$ 2.08	(I)(R)
HADCO Victorian, HPS	150	16,000	62	10.29	2.10	
	200	22,000	79	11.06	2.22	
	250	29,000	102	11.07	2.22	
HADCO Capitol Acorn, HPS	100	9,500	43	14.39	2.56	
	150	16,000	62	14.44	2.61	
	200	22,000	79	14.31	2.60	
	250	29,000	102	14.33	2.61	
Special Architectural Types						
HADCO Independence, HPS	100	9,500	43	10.40	2.08	
	150	16,000	62	10.07	2.05	
HADCO Techtra, HPS	100	9,500	43	19.52	3.14	
	150	16,000	62	19.19	3.12	(I)
	250	29,000	102	18.53	3.08	(R) (I)
HADCO Westbrooke, HPS	70	6,300	30	13.34	2.43	
	100	9,500	43	13.09	2.40	
	150	16,000	62	13.10	2.41	
	200	22,000	79	13.39	2.48	
	250	29,000	102	13.27	2.47	(I)(R)

SCHEDULE 91 (Continued)

RATES FOR CUSTOM LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	
Special Types						
Cobrahead, Metal Halide	150	10,000	60	$ 5.80	$ 1.84	(R)
Flood, Metal Halide	350	30,000	139	8.16	2.15	
Flood, HPS	750	105,000	285	10.25	2.69	(I)
Holophane Mongoose, HPS	150	16,000	62	10.77	2.15	
	250	29,000	102	10.07	2.09	(I)(R) (D)
Option C Only **						
Ornamental Acorn Twin	85	9,600	64	*	*	
Ornamental Acorn	55	2,800	21	*	*	
Ornamental Acorn Twin	55	5,600	42	*	*	
Composite, Twin	140	6,815	54	*	*	
	175	9,815	66	*	*	

* Not offered.
** Rates are based on current kWh energy charges.

RATES FOR CUSTOM POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Aluminum, Regular	16	$ 8.86	$ 0.25	(I)
	25	14.70	0.42	
	30	15.89	0.45	
	35	19.02	0.54	
Aluminum Davit	25	14.67	0.42	
	30	14.60	0.42	
	35	15.97	0.46	
	40	21.68	0.62	
Aluminum Double Davit	30	21.58	0.62	(I)

SCHEDULE 91 (Continued)

RATES FOR CUSTOM POLES (Continued)

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Aluminum, HADCO, Fluted Victorian Ornamental	14	$12.99	$ 0.37	(I)
Aluminum, HADCO, Non-Fluted Techtra Ornamental	18	25.57	0.73	
Aluminum, HADCO, Fluted Ornamental	16	13.28	0.38	
Aluminum, HADCO, Non-Fluted Ornamental	16	27.18	0.78	
Aluminum, HADCO, Fluted Westbrooke	18	25.64	0.73	
Aluminum, HADCO, Non-Fluted Westbrooke	18	27.18	0.78	
Aluminum, Painted Ornamental	35	43.67	1.25	
Concrete. Decorative Ameron	20	25.51	0.73	(R)
Concrete, Ameron Post-Top	25	25.51	0.73	(R)
Fiberglass, HADCO, Fluted Ornamental Black	14	15.70	0.45	
Fiberglass, Smooth	18	6.48	0.19	
Fiberglass, Regular				
color may vary	22	5.80	0.17	
	35	9.53	0.27	
Fiberglass, Anchor Base, Gray	35	17.45	0.50	
Fiberglass, Direct Bury with Shroud	18	10.50	0.30	(I)

(D)

SERVICE RATE FOR OBSOLETE LIGHTING

The following equipment is not available for new installations under Options A and B. To the extent feasible, maintenance will be provided. Obsolete Lighting will be replaced with the Customer's choice of Standard or Custom equipment. The Customer will then be billed at the appropriate Standard or Custom rate. If an existing Mercury Vapor luminaire requires the replacement of a ballast, the unit will be replaced with a corresponding HPS unit.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
Cobrahead, Mercury Vapor	100	4,000	39	*	*	
	175	7,000	66	$ 5.08	$ 1.46	(R)
	250	10,000	94	*	*	
	400	21,000	147	5.82	1.60	(I)
	1,000	55,000	374	6.60	1.92	(I)
Special Box Similar to GE "Space-Glo"						
HPS	70	6,300	30	6.73	1.62	
Mercury Vapor	175	7,000	66	6.68	1.57	(R)

* Not offered.

SCHEDULE 91 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
Special Box, Anodized Aluminum Similar to GardCo Hub						
HPS - Twin	70	6,300	60	*	*	
HPS	70	6,300	30	*	*	
	100	9,500	43	*	$ 1.97	(R)
	150	16,000	62	*	1.99	
	250	29,000	102	*	*	
	400	50,000	163	*	*	
Metal Halide	250	20,500	99	*	1.20	
	400	40,000	156	*	1.20	
Cobrahead, Metal Halide	175	12,000	71	$ 6.08	1.69	
Flood, Metal Halide	400	40,000	156	6.94	1.74	(I)
Cobrahead, Dual Wattage, HPS						
70/100 Watt Ballast	100	9,500	43	*	1.53	
100/150 Watt Ballast	100	9,500	43	*	1.53	
100/150 Watt Ballast	150	16,000	62	*	1.55	(R)
Special Architectural Types Including Philips QL Induction Lamp Systems						
HADCO Victorian, QL	85	6,000	32	*	0.67	(R)(M)
	165	12,000	60	*	0.94	
HADCO Techtra, QL	165	12,000	60	23.22	1.14	(I)(R)(M)
Special Architectural Types						
KIM SBC Shoebox, HPS	150	16,000	62	*	2.55	(R)
KIM Archetype, HPS	250	29,000	102	*	2.81	
	400	50,000	163	*	2.20	
Special Acorn-Type, HPS	70	6,300	30	10.25	2.06	(I)(R)
Special GardCo Bronze Alloy						
HPS	70	5,000	30	*	*	
Mercury Vapor	175	7,000	66	*	*	
Special Acrylic Sphere						
Mercury Vapor	400	21,000	147	*	*	(M)

* Not offered.

SCHEDULE 91 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	
Early American Post-Top, HPS						
Black	70	6,300	30	$5.81	$1.49	(I)(R)(M)
Rectangle Type	200	22,000	79	*	*	
Incandescent	92	1,000	31	*	*	
	182	2,500	62	*	*	
Town and Country Post-Top						
Mercury Vapor	175	7,000	66	5.82	1.50	(I)(R)(M)
Flood, HPS	70	6,300	30	5.20	1.58	
	100	9,500	43	5.17	1.52	
	200	22,000	79	6.69	1.66	(I)
Cobrahead, HPS						
Power Door	310	37,000	124	6.33	2.00	(R)
Special Types Customer-Owned & Maintained						
Ornamental, HPS	100	9,500	43	*	*	
Twin Ornamental, HPS	Twin 100	9,500	86	*	*	
Compact Fluorescent	28	N/A	12	*	*	

* Not offered.

(M)

SCHEDULE 91 (Continued)

RATES FOR OBSOLETE LIGHTING POLES (T)

Type of Pole	Poles Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Aluminum Post	30	$ 8.86	*	(I) (M)
Bronze Alloy GardCo	12	*	$ 0.23	(R)
Concrete, Ornamental	35 or less	14.70	0.42	(I)
Steel, Painted Regular **	25	14.70	0.42	
Steel, Painted Regular **	30	15.89	0.45	
Steel, Unpainted 6-foot Mast Arm **	30	*	0.42	
Steel, Unpainted 6-foot Davit Arm **	30	*	0.42	
Steel, Unpainted 8-foot Mast Arm **	35	*	0.46	
Steel, Unpainted 8-foot Davit Arm **	35	*	0.46	
Wood, Laminated without Mast Arm	20	6.51	0.19	
Wood, Laminated Street Light Only	20	6.51	*	(M)
Wood, Curved Laminated	30	10.26	0.29	
Wood, Painted Underground	35	7.40	0.21	
Wood, Painted Street Light Only	35	7.40	*	(I)

* Not offered.
** Maintenance does not include replacement of rusted steel poles.

(D)(M)

SPECIALTY SERVICES OFFERED

Upon Customer request and subject to the Company's agreement, the Company will provide the following streetlighting services based on the Company's total costs including Company indirect charges:

- Trimming of trees adjacent to streetlight equipment and circuits.
- Arterial patrols to ensure correct operation of streetlights.
- Painting or staining of wood and steel streetlight poles.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 91 (Continued)

SPECIAL CONDITIONS

1. The Company may offer temporary or experimental lighting equipment that is not otherwise listed in this rate schedule. Temporary or experimental lighting will be offered at a billing rate based on approved prices for near equivalent lighting service equipment. The use of temporary or experimental lighting will be for a limited duration not to exceed one-year at which time the lighting service equipment will either be removed at Customer expense or the Company will file with the Commission to add the luminaire type to this rate schedule.

2. Customer is responsible for the cost associated with trenching, boring, conduit and restoration required for underground service to streetlighting.

3. Unless otherwise specifically provided, the location of Company-owned streetlighting equipment and poles may be changed at the Customer's request and upon payment by the Customer of the costs of removal and reinstallation.

4. If Company-owned streetlighting equipment or poles are removed at the Customer's request, a charge will be made consisting of the estimated original cost, less depreciation, less salvage value, plus removal cost. This provision does not pertain to the sale of Company-owned equipment. This condition applies if a Customer's selection of service under this Schedule requires the removal of Company-owned streetlighting equipment or poles.

5. If circuits or poles not already covered under Special Condition 2 or 3 are removed or relocated at the Customer's request, the Customer is responsible for all associated costs for labor and materials incurred when fulfilling this request.

6. For Option C lights: The Company does not provide the circuit on new Option C (C)
installations. (C)

7. For Option C lights in service prior to January 31, 2006: When the Company furnishes Electricity to luminaires owned and maintained by the Customer and installed on Customer-owned poles that are not included in the list of equipment in this schedule, usage for the luminaire will be estimated by the Company. When the Customer and the Company cannot agree, the Commission will determine the estimated usage.

8. For Option A and Option B lights: The Company shall not be liable when either (i) the luminaires become inoperable or (ii) repair or replacement of inoperable luminaires is delayed or prevented; provided that, such inoperability of the luminaires or delay or prevention of repair or replacement is due to any cause beyond the Company's control, or that otherwise could not reasonably be foreseen or guarded against including but not limited to such causes as: strikes, lockouts, labor troubles, riots, insurrection, war, acts of God, extreme weather conditions, access to equipment, or the like.

SCHEDULE 92
TRAFFIC SIGNALS
(NO NEW SERVICE)
STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments where funds for payment of Electricity are provided through taxation or property assessment for traffic signals and warning facilities in systems containing at least 50 intersections on public streets and highways. This schedule is available only to those governmental agencies receiving service under Schedule 92 as of September 30, 2001.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Transmission and Related Services Charge	0.171 ¢ per kWh	(R)
Distribution Charge	2.215 ¢ per kWh	(I)
Energy Charge	5.204 ¢ per kWh	(R)

* See Schedule 100 for applicable adjustments.

ELECTION WINDOW

Balance-of-Year Election Window

The Balance-of-Year Election Window begins at 8:00 a.m. on February 15th. The Window will remain open from 8:00 a.m. of the first day through 5:00 p.m. of the third business day of the Election Window.

Balance-of-Year Election Window, a Customer may notify the Company of its choice to move to Direct Access Service. For the February 15th election, the move is effective on the following April 1st. A Customer may not choose to move from an alternative option back to Cost of service during a Balance-of-Year Election Window.

SCHEDULE 95
STREET AND HIGHWAY LIGHTING
NEW TECHNOLOGY
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments for lighting service utilizing Company approved new technology streetlighting equipment for public streets and highways and public grounds where funds for payment of Electricity generally are provided through taxation or property assessment.

CHARACTER OF SERVICE

From dusk to dawn daily, controlled by a photoelectric control to be mutually agreeable to the Customer and Company for an average of 4,100 hours annually.

LUMINAIRE SERVICE OPTIONS - The Company offers the following Luminaire Service Options at the applicable rates specified herein.

The Customer will elect the Luminaire Service Option at the time of initial luminaire installation.

Option A - Luminaire

Option A provides electricity service to luminaires that are purchased, owned, and maintained by the Company with attachment to Company-owned poles at the monthly Option A rate applicable to the installed type of light.

Maintenance Service under Option A

The Company will only perform emergency maintenance on the luminaires listed in this schedule. The Company does not perform preventative maintenance on the luminaires listed in this schedule.

The Company will repair or replace inoperable luminaires as soon as reasonably possible, subject to the Company's operating schedule, following notification to PGE's Customer Service or PGE's Outdoor Lighting Services[1] department by the Customer, a member of the public, or a PGE employee performing luminaire replacement work. PGE has no obligation for repair or replacement of inoperable luminaires other than as described in this section of the tariff. (C)

(1) Contact PGE's Outdoor Lighting Services at 503-736-5710, PGE's Customer Service 503-228-6322 or 1-800-542-8818, or www.portlandgeneral.com to report an inoperable streetlight.

SCHEDULE 95 (Continued)

STREETLIGHT POLES SERVICE OPTIONS

See Schedule 91 for Streetlight poles service options.

MONTHLY RATE

In addition to the service rates for Option A lights, all Customers will pay the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Transmission and Related Services Charge	0.182 ¢ per kWh	(R)
Distribution Charge	4.682 ¢ per kWh	(I)
Energy Charge		
Cost of Service Option	5.078 ¢ per kWh	(R)

NON-COST OF SERVICE OPTION

Daily Price Option – Available only to Customers with an average load of five MW or greater on Schedules 91 and 95 and those customers that met the five MW or greater threshold prior to converting to lights from Schedule 91 to Schedule 95. This selection of this option applies to all luminaires served under Schedules 91 and 95. This option gives eligible Customers an option between a daily Energy price and a Cost of Service option for the Energy charge. In addition to the daily Energy price, the Customer will pay a Basic Charge of $75 per month to help offset the costs of billing this option. The daily Energy price for all kWh will be the Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Firm Index) plus 0.294¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. (I)

Prices reported with no transaction volume or as "survey-based" will be considered reported. For the purposes of calculating the daily on- and off-peak usage, actual kWhs will be determined for each month, using Sunrise Sunset Tables with adjustments for typical photocell operation and 4,100 annual burning hours.

For Customers billed on the Daily Price Option, an average of the daily rates will be used to bill installations and removals that occur during the month. Any additional analysis of billing options and price comparisons beyond the monthly bill will be billed at a rate of $100 per manhour.

Losses will be included by multiplying the applicable daily Energy price by 1.0820.

The Daily Price Option is subject to Schedule 128, Short Term Transition Adjustment.

SCHEDULE 95 (Continued)

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rate [1]	Straight Time	Overtime
	\$120.00 per hour	\$167.00 per hour

[1] Per Article 20.2 of the Collective Bargaining Agreement Union No. 125 Contract, overtime is paid at the Overtime Rate for a minimum of one hour.

RATES FOR STANDARD LIGHTING

Light-Emitting Diode (LED) Only – Option A Service Rates

LED lighting is new to the Company and pricing is changing rapidly. The Company may adjust rates under this schedule based on actual frequency of maintenance occurrences and changes in material prices.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rate Option A	
LED	37	2,530	13	\$3.46	(R)
LED	50	3,162	17	3.46	
LED	52	3,757	18	3.88	
LED	67	5,050	23	4.36	
LED	106	7,444	36	5.22	(R)

SCHEDULE 95 (Continued)

SPECIAL CONDITIONS

1. Customer is responsible for the cost associated with trenching, boring, conduit and restoration required for underground service to streetlighting.

2. Unless otherwise specifically provided, the location of Company-owned streetlighting equipment and poles may be changed at the Customer's request and upon payment by the Customer of the costs of removal and reinstallation.

3. If Company-owned streetlighting equipment or poles are removed at the Customer's request, a charge will be made consisting of the estimated original cost, less depreciation, less salvage value, plus removal cost. This provision does not pertain to the sale of Company-owned equipment. This condition applies if a Customer's selection of service under this Schedule requires the removal of Company-owned streetlighting equipment or poles.

4. If circuits or poles not already covered under Special Conditions 2 or 3 are removed or relocated at the Customer's request, the Customer is responsible for all associated costs for labor and materials incurred when fulfilling this request.

5. For Option C lights: The Company does not provide the circuit on new installations. (C)

6. For Option A lights: The Company shall not be liable when either (i) the luminaires become inoperable or (ii) repair or replacement of inoperable luminaires is delayed or prevented; provided that, such inoperability of the luminaires or delay or prevention of repair or replacement is due to any cause beyond the Company's control, or that otherwise could not reasonably be foreseen or guarded against including but not limited to such causes as: strikes, lockouts, labor troubles, riots, insurrection, war, acts of God, extreme weather conditions, access to equipment, or the like.

7. For Option C lights: The Customer must ensure that (i) all maintenance and other work associated with this schedule is in compliance with the applicable requirements of OSHA, OPUC Safety Rules, the NESC and/or NEC and (ii) that all such work is performed by a Qualified Worker. A "Qualified Worker" means one who is knowledgeable about the construction and operation of the electric power generation, transmission, and distribution equipment as it relates to his or her work, along with the associated hazards, as demonstrated by satisfying the qualifying requirements for a "qualified person" or "qualified employee" with regard to the work in question as described in 29 CFR 1910.269 effective January 31, 1994, as it may be amended from time to time. In this case, a Qualified Worker is a journeyman lineman, or someone who has the equivalent training, expertise and experience to perform journeyman lineman work.

SCHEDULE 123
DECOUPLING ADJUSTMENT

PURPOSE

This Schedule establishes balancing accounts and rate adjustment mechanisms to track and mitigate a portion of the transmission, distribution and fixed generation revenue variations caused by variations in applicable Customer Energy usage.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all Residential and Nonresidential Customers located within the Company's service territory except those Nonresidential Customers whose load exceeded one aMW at a Point of Delivery during the prior calendar year or those Nonresidential Customers qualifying as a Self-Directing Customer. Customers so exempted will not be charged the prices contained in this schedule.

DEFINITIONS

For the purposes of this tariff, the following definition will apply:

Energy Efficiency Measures (EEMs) – Actions that enable customers to reduce energy use. EEMs can be behavioral or equipment-related.

Self-Directing Customer (SDC) - Pursuant to OAR 860-038-0480, to qualify to be a SDC, the Large Nonresidential Customer must have a load that exceeds one aMW at a Site as defined in Rule B and receive certification from the Oregon Department of Energy as an SDC.

SALES NORMALIZATION ADJUSTMENT (SNA)

The SNA reconciles on a monthly basis, for Customers served under Schedules 7, 32 and 532, differences between a) the monthly revenues resulting from applying distribution, transmission and fixed generation charges (Fixed Charge Energy Rate) of 6.630 cents/kWh for Schedule 7 **(I)**
and 6.407 cents/kWh for Schedules 32 and 532 to weather-normalized kWh Energy sales, and **(I)**
b) the Fixed Charge Revenues that would be collected by applying the Monthly Fixed Charge per Customer of $56.77 per month for Schedule 7 and $95.05 per month for Schedules 32 and **(I)**
532 to the numbers of active Schedule 7 and Schedule 32 and 532 Customers, respectively, for each month.

The SNA will calculate monthly as the Fixed Charge Revenue less actual weather-adjusted revenues and will accrue to the SNA Balancing Account. The monthly amount accrued may be positive (an under-collection) or negative (an over-collection). The SNA is divided into sub-accounts so that net accruals for Schedule 7 will track separately from the net accruals for Schedules 32 and 532.

SCHEDULE 123 (Continued)

NONRESIDENTIAL LOST REVENUE RECOVERY ADJUSTMENT (LRRA)

The Nonresidential Lost Revenue Recovery Adjustment is applicable to all customers except those served under Schedules 7, 32 and 532 or as otherwise exempted above. Nonresidential Lost Revenue Recovery amounts will be equal to the reduction in distribution, transmission, and fixed generation revenues due to the reduction in kWh sales as reported to the Company by the Energy Trust of Oregon, resulting from EEMs implemented during prior calendar years attributable to EEM funding incremental to Schedule 108, adjusted for EEM program kWh savings incorporated into the test year load forecast used to determine base rates. Also included are differences in actual energy savings from a test year forecast associated with the (C) conversion to LED streetlighting in Schedule 95 reported by the Company. When base rates are adjusted in the future as a result of a general rate review, the test year load forecast used to determine new base rates will reflect all energy efficiency kWh savings that have been previously achieved. The cumulative kWh savings are eligible for Lost Revenue Recovery until new base rates are established as a result of a general rate review; the kWh base is then reset to equal the amount of kWh savings that accrue from EEMs following an adjustment in base rates.

The Lost Revenue Recovery Adjustment may be positive or negative. A negative Lost Revenue Recovery Adjustment for a given test year will occur if kWh savings reported by the Energy Trust of Oregon, plus the energy savings associated with the conversion to LED streetlighting in Schedule 95, are less than those estimated in setting base rates. A positive Lost Revenue Recovery Adjustment for a given test year will occur if kWh savings reported by the Energy Trust of Oregon, plus the energy savings associated with the conversion to LED streetlighting in Schedule 95, are greater than those estimated for the test year in setting base rates. The LRRA for each year subsequent to the test year will incorporate incremental kWh savings reported by the Energy Trust of Oregon for that year.

For the purposes of this Schedule, the Lost Revenue Recovery Adjustment is the product of: (1) the reduction in kWh sales resulting from ETO-reported EEMs plus the energy savings associated with the conversion to LED streetlighting in Schedule 95, and (2) the weighted average of applicable retail base rates (the Lost Revenue Rate). Applicable base rates for Nonresidential Customers are defined as the schedule-weighted average of transmission, distribution, and fixed generation charges; including those contained in Schedule122 and other applicable schedules. System usage or distribution charges will be adjusted to include only the recovery of Trojan Decommissioning expenses and the Customer Impact Offset. Franchise fee recovery is not included in the Lost Revenue Rate. The applicable Lost Revenue Rate is 4.464 (I) cents per kWh.

SNA and LRRA BALANCING ACCOUNTS

The Company will maintain a separate balancing account for the SNA, applicable to Schedules 7, 32 and 532, and for the Nonresidential LRRA for the remaining applicable nonresidential Schedules. Each balancing account will record over- and under-collections resulting from differences as determined, respectively, by the SNA and LRRA mechanisms. The accounts will accrue interest at the Commission-authorized Modified Blended Treasury Rate established for deferred accounts.

SCHEDULE 123 (Continued)

DECOUPLING ADJUSTMENT (Continued)

Schedule	Adjustment Rate
589	
Secondary	(0.011) ¢ per kWh
Primary	(0.011) ¢ per kWh
Subtransmission	(0.011) ¢ per kWh
591	(0.011) ¢ per kWh
592	(0.011) ¢ per kWh
595	(0.011) ¢ per kWh

TIME AND MANNER OF FILING

Commencing in 2014, the Company will submit to the Commission the following information by November 1 of each year: (C)

1. The proposed price changes to this Schedule to be effective on January 1st of the subsequent year based on a) the amounts in the SNA Balancing Accounts and b) the amount in the LRRA Balancing Account. (C)

2. Revisions to this Schedule which reflect the new proposed prices and supporting work papers detailing the calculation of the new proposed prices and the SNA weather-normalizing adjustments.

(D)

SCHEDULE 123 (Concluded)

SPECIAL CONDITIONS

1. The Fixed Charge Energy Rate, Monthly Fixed Charge per Customer and the Lost Revenue Rate will be updated concurrently with a change in the applicable base revenues used to determine the rates.

2. Weather-normalized energy usage by applicable rate schedule will be determined in a manner equivalent to that used for determining the forecasted loads used to establish base rates.

3. No revision to any SNA or LRRA Adjustment Rate will result in an estimated average annual rate increase greater than 2% to the applicable SNA or LRRA rate schedule, based on the net rates in effect on the effective date of the Schedule 123 rate revisions. Rate revisions resulting in a rate decrease are not subject to the 2% limit.

(D)

SCHEDULE 125
ANNUAL POWER COST UPDATE

PURPOSE

The purpose of this adjustment schedule is to define procedures for annual rate revisions due to changes in the Company's projected Net Variable Power Costs (the Annual Power Cost Update). This schedule is an "automatic adjustment clause" as defined in ORS 757.210(1), and is subject to review by the Commission at least once every two years.

APPLICABLE

To all Cost-of-Service bills for Electricity Service served under the following rate schedules 7, 15, 32, 38, 47, 49, 75, 83, 85, 89, 91, 92, and 95. Customers served under the daily price option contained in schedules 32, 38, 75, 81, 83, 85, 89, 91 and 95 are exempt from Schedule 125. **(C)**

NET VARIABLE POWER COSTS

Net Variable Power Costs (NVPC) are the power costs for energy generated and purchased. NVPC are the net cost of fuel and emission control chemicals, fuel and emission control chemical transportation, power contracts, transmission/wheeling, wholesale sales, hedges, options and other financial instruments incurred to serve retail load. **(C)** **(C)**

RATES

This adjustment rate is subject to increases or decreases, which may be made without prior hearing, to reflect increases or decreases, or both, in NVPC.

ANNUAL UPDATES

The following updates will be made in each of the Annual Power Cost Update filings:

- Forced Outage Rates based on a four-year rolling average.
- Projected planned plant outages.
- Wind energy forecast based on a five-year rolling average. **(N)**
- Costs associated with wind integration. **(N)**
- Forward market prices for both gas and electricity.
- Projected loads.
- Contracts for the purchase or sale of power and fuel.
- Emission control chemical costs. **(N)**
- Thermal plant variable operation and maintenance, including the cost of transmission losses, for dispatch purposes. **(C)** **(C)**
- Changes in hedges, options, and other financial instruments used to serve retail load.
- Transportation contracts and other fixed transportation costs.
- No other changes or updates will be made in the annual filings under this schedule.

(M)

SCHEDULE 125 (Continued)

CHANGES IN NET VARIABLE POWER COSTS **(M)**

Changes in NVPC for purposes of rate determination under this schedule are the projected NVPC as determined in the Annual Power Cost Update less the NVPC revenues that would occur at the NVPC prices determined in the Company's most recent general rate case, adjusted for a revenue sensitive cost factor of 1.0336. **(R)(M)**

FILING AND EFFECTIVE DATE

On or before April 1st of each calendar year, the Company will file estimates of the adjustments to its NVPC to be effective on January 1st of the following calendar year.

On or before October 1st of each calendar year, the Company will file updated estimates with final planned maintenance outages, final load forecast, updated projections of gas and electric prices, power, and fuel contracts.

On November 15th, the Company will file the final estimate of NVPC and will calculate and file the final change in NVPC to be effective on the next January 1st with: 1) projected market electric and fuel prices based on the average of the Company's internally generated projections made during the period November 1st through November 7th, 2) load reductions from the October update resulting from additional participation in the Company's Long-Term Cost of Service Opt-out that occurs in September, 3) new market power and fuel contracts entered into since the previous updates, and 4) the final planned maintenance outages and load forecast from the October 1st filing.

RATE ADJUSTMENT

The rate adjustment will be based on the Adjusted NVPC less the NVPC revenues that would occur at the NVPC prices determined in the Company's most recent general rate case applied to forecast loads used to determine changes in Net Variable Power Costs. NVPC prices are defined as the price component that recovers the level of NVPC from the Company's most recent general rate case contained in each Schedule's Cost of Service energy prices.

(M)

SCHEDULE 125 (Concluded)

ADJUSTMENT RATES (T)

Schedule		Part A ¢ per kWh
7		0.000
15		0.000
32		0.000
38	Large Nonresidential	0.000
47		0.000
49		0.000
75		
	Secondary	0.000 (1)
	Primary	0.000 (1)
	Subtransmission	0.000 (1)
83		0.000
85		
	Secondary	0.000
	Primary	0.000
89		
	Secondary	0.000
	Primary	0.000
	Subtransmission	0.000
91		0.000
92		0.000
95		0.000

(I)(M) (M) (I)

(1) Applicable only to the Baseline and Scheduled Maintenance Energy. (T)

SPECIAL CONDITIONS

1. Costs recovered through this schedule will be allocated to each schedule using the applicable schedule's forecasted energy on the basis of an equal percent of generation revenue applied on a cents per kWh basis to each applicable rate schedule.

SCHEDULE 126
ANNUAL POWER COST VARIANCE MECHANISM

PURPOSE

To recognize in rates part of the difference for a given year between Actual Net Variable Power Costs and the Net Variable Power Costs forecast pursuant to Schedule 125, Annual Power Cost Update and in accordance with Commission Order No. 07-015. This schedule is an "automatic adjustment clause" as defined in ORS 757.210.

APPLICABLE

To all Customers for Electricity Service except those who were served on Schedule 76R and 576R, 485, 489, 515, 532, 538, 549, 583, 585, 589, 591, 592 and 595, or served under Schedules 83, 85 or 89 Daily Price Option for the entire calendar year that the Annual Power Cost Variance accrued. Customers served on Schedules 538, 583, 585, 589, 591, 592 and 595 who received the Schedule 128 Balance of Year Transition Adjustment will be subject to this adjustment.

ANNUAL POWER COST VARIANCE

Subject to the Earnings Test, the Annual Power Cost Variance (PCV) is 90% of the amount that the Annual Variance exceeds either the Positive Annual Power Cost Deadband for a Positive Annual Variance or the Negative Annual Power Cost Deadband for a Negative Annual Variance.

POWER COST VARIANCE ACCOUNT

The Company will maintain a PCV Account to record Annual Variance amounts. The Account will contain the difference between the Adjustment Amount and amounts credited to or collected from Customers. This account will accrue interest at the Commission-authorized rate for deferred accounts. At the end of each year the Adjustment Amount for the calendar year will be adjusted by 50% of the annual interest calculated at the Commission-authorized rate. This amount will be added to the Adjustment Account.

Any balance in the PCV Account will be amortized to rates over a period determined by the Commission. Annually, the Company will propose to the Commission PCV Adjustment Rates that will amortize the PCV to rates over a period recommended by the Company. The amount accruing to Customers, whether positive or negative, will be multiplied by a revenue sensitive factor of 1.0336 (R)
to account for franchise fees, uncollectibles, and OPUC fees.

EARNINGS TEST

The recovery from or refund to Customers of any Adjustment Amount will be subject to an earnings review for the year that the power costs were incurred. The Company will recover the Adjustment Amount to the extent that such recovery will not cause the Company's Actual Return on Equity (ROE) for the year to exceed its Authorized ROE minus 100 basis points. The Company will refund the Adjustment Amount to the extent that such refunding will not cause the Company's Actual Return on Equity (ROE) for the year to fall below its Authorized ROE plus 100 basis points.

Schedule 126 (Continued)

DEFINITIONS (Continued)

Net Variable Power Costs (NVPC)

The Net Variable Power Costs (NVPC) represents the power costs for Energy generated and purchased. NVPC are the net cost of fuel and emission control chemicals, fuel and emission control chemical transportation, power contracts, transmission/wheeling, wholesale sales, hedges, options and other financial instruments incurred to serve retail load. For purposes of calculating the NVPC, the following adjustments will be made: **(C)** **(C)**

- Exclude BPA payments in lieu of Subscription Power.
- Exclude the monthly FASB 133 mark-to-market activity.
- Exclude any cost or revenue unrelated to the period.
- Include as a cost all losses that the Company incurs, or is reasonably expected to incur, as a result of any non-retail Customer failing to pay the Company for the sale of power during the deferral period.
- Include fuel costs and revenues associated with steam sales from the Coyote Springs I Plant.
- Include gas resale revenues.
- Include Energy Charge revenues from Schedules 76R, 38, 83, 85, 89, and 91 Energy pricing options other than Cost of Service and the Energy Charge revenues from the Market Based Pricing Option from Schedules 485 and 489 as an offset to NVPC.
- NVPC shall be adjusted as needed to comply with Order 07-015 that states that ancillary services, the revenues from sales as well as the costs from the services, should also be taken into account in the mechanism.
- Actual NVPC will be increased to include the value of the energy associated with those Customers that received the Schedule 128 Balance of Year Transition Adjustment for the period during the year that the Customers received the Schedule 128 adjustment.

ADJUSTMENT AMOUNT

The amount accruing to the Power Cost Variance Account, whether positive or negative will be multiplied by a revenue sensitive factor of 1.0336 to account for franchise fees, uncollectables, and OPUC fees. **(R)**

The Power Cost Adjustment Rate shall be set at level such that the projected amortization for 12 month period beginning with the implementation of the rate is no greater than six percent (6%) of annual Company retail revenues for the preceding calendar year.

TIME AND MANNER OF FILING

As a minimum, on July 1st of the following year (or the next business day if the 1st is a weekend or holiday), the Company will file with the Commission recommended adjustment rates for the next calendar year.

SCHEDULE 128
SHORT-TERM TRANSITION ADJUSTMENT

PURPOSE

The purpose of this Schedule is to calculate the Short-Term Transition Adjustment to reflect the results of the ongoing valuation under OAR 860-038-0140.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all Nonresidential Customers served who receive service at Daily pricing (other than Cost of Service) on Schedules 32, 38, 75, 83, 85, 89, 91 or 95 or Direct Access service on Schedules 515, 532, 538, 549, 575, 583, 585, 589, 591, 592 and 595. This Schedule is not applicable to Customers served on Schedules 485 and 489.

SHORT-TERM TRANSITION ADJUSTMENT

The Short-Term Transition Adjustment will reflect the difference between the Energy Charge(s) under the Cost of Service Option including Schedule 125 and the market price of power for the period of the adjustment applied to the load shape of the applicable schedule.

ANNUAL SHORT-TERM TRANSITION ADJUSTMENT RATE

For Customers who have made a service election other than Cost of Service for 2013, the Annual Short-Term Transition Adjustment Rate will be applied to their bills for service effective on and after January 1, 2014: (C)
(C)

Schedule		Annual ¢ per kWh [1]	
32		2.076	(R)
38		1.984	
75	Secondary	1.108 [2]	(C)
	Primary	1.419 [2]	
	Subtransmission	1.396 [2]	
83		1.964	
85	Secondary	1.771	
	Primary	1.731	(C)(R)

(1) Not applicable to Customers served on Cost of Service.
(2) Applicable only to the Baseline and Scheduled Maintenance Energy.

SCHEDULE 128 (Continued)

ANNUAL SHORT-TERM TRANSITION ADJUSTMENT RATE (Continued)

Schedule		Annual ¢ per kWh [(1)]	
89	Secondary	1.108	(C)(R)
	Primary	1.419	
	Subtransmission	1.396	
91		1.365	
95		1.365	
515		1.365	
532		2.076	
538		1.984	
549		3.316	
575	Secondary	1.108 [(2)]	
	Primary	1.419 [(2)]	
	Subtransmission	1.396 [(2)]	
583		1.964	
585	Secondary	1.771	
	Primary	1.731	
589	Secondary	1.108	
	Primary	1.419	
	Subtransmission	1.396	
591		1.365	
592		1.315	(C)(R)
595		1.365	

(1) Not applicable to Customers served on Cost of Service.
(2) Applicable only to the Baseline and Scheduled Maintenance Energy.

ANNUAL SHORT-TERM TRANSITION ADJUSTMENT REVISIONS

The Annual Short-Term Transition Adjustment rate will be filed on November 15th (or the next business day if the 15th is a weekend or holiday) to be effective for service on and after January 1st of the next year. Indicative, non-binding estimates for the Annual Short-Term Transition Adjustment and Cost-of-Service Energy Prices will be posted by the Company by September 1 and then again one week prior to the filing date. These prices will be for informational purposes only and are not to be considered the adjustment rates.

SCHEDULE 128 (Concluded)

Second Quarter – April 1st Balance of Year Adjustment Rate (1)

Schedule		Annual ¢ per kWh (2)	
38		0.000	(C)
75	Secondary	0.000 (3)	
	Primary	0.000 (3)	
	Subtransmission	0.000 (3)	
83		0.000	
85	Secondary	0.000	
	Primary	0.000	
89	Secondary	0.000	
	Primary	0.000	
	Subtransmission	0.000	
91		0.000	
95		0.000	
538		0.000	
575	Secondary	0.000 (3)	
	Primary	0.000 (3)	
	Subtransmission	0.000 (3)	
583		0.000	
585	Secondary	0.000	
	Primary	0.000	
589	Secondary	0.000	
	Primary	0.000	
	Subtransmission	0.000	
591		0.000	
592		0.000	
595		0.000	(C)

(1) Applicable April 1, 2014 through December 31, 2014. (C)
(2) Not applicable to Customers served on Cost of Service.
(3) Applicable only to the Baseline and Scheduled Maintenance Energy.

SCHEDULE 129 (Concluded)

SPECIAL CONDITIONS

1. Annually, the total amount paid in Schedule 129 Long-Term Transition Cost Adjustment will be collected through applicable Large Nonresidential rate schedules (Schedules 75, 76R, 85, 89, 485, 489, 575, 576R, 585, and 589), through either the System Usage or Distribution Charges. Such adjustment to the System Usage or Distribution Charges will be made at the time the Company files final rates for Schedule 125, and will be effective on January 1st of the following calendar year.

2. Annually, changes in fixed generation revenues resulting from either return to or departure from Cost of Service pricing by Schedule 485 and 489 customers relative to the Company's most recent general rate case will be incorporated into the System Usage Charges of the Large Nonresidential Rate Schedules 75, 76R, 85, 89, 485, 489, 575, 576R, 585, and 589. Such adjustment to the System Usage or Distribution Charges will be made at the time the Company files final rates for Schedule 125, and will be effective on January 1st of the following calendar year. The adjustment to the System Usage Charge resulting from changes in fixed generation revenues shall not result in a rate increase or decrease to Schedules 85, and 89 of more than 2 percent except as noted below. For those Enrollment Periods in which the first-year Schedule 129 Transition Adjustments are expected to be positive charges to participants, the projected first-year revenues from Schedule 129 will be netted against the changes in fixed generation costs for purposes of calculating the proposed rate increase or decrease to Schedules 85 and 89. Should the rate increase or decrease for Schedules 85 and 89 exceed 2 percent, the amounts exceeding 2 percent will be deferred for future recovery through a balancing account. This balancing account will be considered an "Automatic Adjustment Clause" as defined in ORS 757.210. For purposes of calculating the percent change in rates, Schedule 125 prices with and without the increased/decreased Schedules 485 and 489 participating load will be determined.

3. In determining changes in fixed generation revenues from movement to or from Schedules 485 and 489, the following factors will be used:

Schedule		¢ per kWh	
85	Secondary	2.335	(I)
	Primary	2.260	
89	Secondary	2.189	
	Primary	2.108	
	Subtransmission	2.079	(I)

TERM

The term of applicability under this schedule will correspond to a Customer's term of service under Schedule 485 or 489.

SCHEDULE 145
BOARDMAN POWER PLANT
DECOMISSIONING ADJUSTMENT (C)

PURPOSE

This schedule establishes the mechanism to implement in rates the revenue requirement effect of the decommissioning expenses related to the Boardman power plant. This schedule is implemented as an "automatic adjustment clause" as defined in ORS 757.210. (C) (C)

APPLICABLE

To all bills for Electricity Service except Schedules 76R, 485, 489 and 576R.

ADJUSTMENT RATES

Schedule 145 Adjustment Rates will be set based an equal percent of Energy Charge revenues applicable at the time of any filing that revises rates pursuant to this schedule.

Schedule	Adjustment Rate	
7	0.014 ¢ per kWh	(R)
15	0.011 ¢ per kWh	
32	0.013 ¢ per kWh	
38	0.013 ¢ per kWh	
47	0.016 ¢ per kWh	
49	0.015 ¢ per kWh	
75		
Secondary	0.011 ¢ per kWh	
Primary	0.011 ¢ per kWh	
Subtransmission	0.011 ¢ per kWh	
83	0.012 ¢ per kWh	
85		
Secondary	0.012 ¢ per kWh	
Primary	0.012 ¢ per kWh	(R)

SCHEDULE 145 (Continued)

ADJUSTMENT RATE (Continued)

Schedule	Adjustment Rate	
89		
Secondary	0.011 ¢ per kWh	(R)
Primary	0.011 ¢ per kWh	
Subtransmission	0.011 ¢ per kWh	
91	0.011 ¢ per kWh	
92	0.011 ¢ per kWh	
95	0.011 ¢ per kWh	(D)
515	0.011 ¢ per kWh	
532	0.013 ¢ per kWh	
538	0.013 ¢ per kWh	
549	0.015 ¢ per kWh	
575		
Secondary	0.011 ¢ per kWh	
Primary	0.011 ¢ per kWh	
Subtransmission	0.011 ¢ per kWh	
583	0.012 ¢ per kWh	
585		
Secondary	0.012 ¢ per kWh	
Primary	0.012 ¢ per kWh	
589		
Secondary	0.011 ¢ per kWh	
Primary	0.011 ¢ per kWh	
Subtransmission	0.011 ¢ per kWh	
591	0.011 ¢ per kWh	
592	0.011 ¢ per kWh	
595	0.011 ¢ per kWh	(R)

SCHEDULE 145 (Concluded)

DETERMINATION OF ADJUSTMENT AMOUNT

(D)

The Adjustment Amount is the revenue requirements related to decommissioning of the Boardman Power Plant using a plant end of life assumption of year-end 2020. The decommissioning revenue requirement computation will use the Commission-authorized tax rates, revenue sensitive cost rates, rate of return and return on equity rates. Only changes to decommissioning expense are included in the revenue requirements. (C) (C)

The Adjustment Rates will be updated annually to reflect the subsequent year's change in the Boardman Power Plant decommissioning revenue requirement. (T)

(D)

BALANCING ACCOUNT

The Company will maintain a balancing account to track the difference between the Schedule 145 Decommissioning Revenue Requirements and the actual Schedule 145 revenues. This difference will accrue interest at the Commission-authorized rate for deferred accounts. (T)

TIME AND MANNER OF FILING

Commencing in 2011, the Company will submit to the Commission the following information by November 1 of each year:

1. The proposed price changes to this Schedule to be effective on January 1st of the following year based on the updated revenue requirements described above.

2. Work papers supporting the Schedule 145 prices, the updated decommissioning revenue requirements, the projected applicable billing determinants, and the projected balancing account activity. (T)

SCHEDULE 485
LARGE NONRESIDENTIAL
COST OF SERVICE OPT-OUT
(201 - 4,000 kW) **(C)**

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has exceeded 200 kW more than six times in the preceding 13 months but has not exceeded 4,000 kW more than once in the preceding 13 months, or with seven months or less of service has not had a Demand exceeding 4,000 kW and who has chosen the Company's transition plan during one of the enrollment periods specified below. To obtain service under this schedule, Customers must enroll a minimum of 1 MWa determined by a demonstrated usage pattern such that projected usage for a full 12 months is at least 8,760,000 kWh (1 MWa) from one or more Points of Delivery (POD). Each POD must have a Facility Capacity of at least 250 kW. Service under this schedule is limited to the first 300 MWa that applies to this and Schedule 489. Beginning with the September 2004 Enrollment Period C, Customers have a minimum five-year option and a fixed three-year option. **(C)** **(C)**

ENROLLMENT PERIODS

ENROLLMENT PERIODS	MINIMUM FIVE-YEAR OPTION
Enrollment Period A:	January 1, 2003 through December 31, 2007
Enrollment Period B:	January 1, 2004 through December 31, 2008
Enrollment Period C:	January 1, 2005 through December 31, 2009
Enrollment Period D:	January 1, 2006 through December 31, 2010
Enrollment Period E:	January 1, 2007 through December 31, 2011
Enrollment Period F:	January 1, 2008 through December 31, 2012
Enrollment Period G:	January 1, 2009 through December 31, 2013
Enrollment Period H:	January 1, 2010 through December 31, 2014
Enrollment Period I:	January 1, 2011 through December 31, 2015
Enrollment Period J:	January 1, 2012 through December 31, 2016
Enrollment Period K:	January 1, 2013 through December 31, 2017

SCHEDULE 485 (Continued)

CHANGE IN APPLICABILITY

If a Customer's usage changes such that their facility capacity falls below 201 kW, they will have their service terminated under this schedule and will be moved to an otherwise applicable schedule.

MONTHLY RATE

The Monthly Rate will be the sum of the following charges at the applicable Delivery Voltage per POD*:

	Delivery Voltage		
	Secondary	Primary	
Basic Charge	$370.00	$390.00	(I)
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 200 kW	$3.12	$3.04	(I)
Over 200 kW	$2.12	$2.04	(R)(I)
per kW of monthly On-Peak Demand	$2.05	$1.99	(I)
System Usage Charge			
per kWh	0.042 ¢	0.040 ¢	(R)

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the POD.

MARKET BASED PRICING OPTION

Energy Supply

The Customer may elect to purchase Energy from an Electricity Service Supplier (ESS) (Direct Access Service) or from the Company. Such election will be for all of the Customer's POD under this schedule.

Direct Access Service

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS.

SCHEDULE 485 (Continued)

MARKET BASED PRICING OPTION (Continued)

Company Supplied Energy

Upon not less than five business days notice, the Customer may choose the Company Supplied Energy Charge option. The election of this option will be effective on the next regularly scheduled meter reading date, but with not less than a five business day notice to the Company prior to the scheduled meter read date.

The Company Supplied Energy Option is the Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Index) plus 2 mills per kWh plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported.

Wheeling Charge

The Wheeling Charge will be $1.713 per kW of monthly Demand. **(I)**

Transmission Charge

Transmission and Ancillary Service Charges will be as specified in the Company's Open Access Transmission Tariff (OATT) as filed and approved by the Federal Energy Regulatory Commission.

FACILITY CAPACITY

The Facility Capacity will be the average of the two greatest non-zero monthly Demands established anytime during the 12-month period which includes and ends with the current Billing Period.

MINIMUM CHARGE

The minimum charge will be the Basic and Distribution Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher minimum charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in Facilities. The minimum monthly On-Peak Demand (in kW) will be 100 kW for primary voltage service.

SCHEDULE 489
LARGE NONRESIDENTIAL
COST-OF-SERVICE OPT-OUT
(>4,000 kW) **(C)**

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has exceeded 4,000 kW more than once within the preceding 13 months and who has chosen the Company's transition plan during one of the enrollment periods specified below. To obtain service under this schedule, Customers must enroll a minimum of 1 MWa determined by a demonstrated usage pattern such that projected usage for a full 12 months is at least 8,760,000 kWh (1 MWa) from one or more Points of Delivery (POD). Each POD must have a Facility Capacity of at least 250 kW. Service under this schedule is limited to the first 300 MWa that applies to this and Schedule 485. Beginning with the September 2004 Enrollment Period C, Customers have a minimum five-year option and a fixed three-year option. **(C)**

ENROLLMENT PERIODS

ENROLLMENT PERIODS	MINIMUM FIVE-YEAR OPTION
Enrollment Period A:	January 1, 2003 through December 31, 2007
Enrollment Period B:	January 1, 2004 through December 31, 2008
Enrollment Period C:	January 1, 2005 through December 31, 2009
Enrollment Period D:	January 1, 2006 through December 31, 2010
Enrollment Period E:	January 1, 2007 through December 31, 2011
Enrollment Period F:	January 1, 2008 through December 31, 2012
Enrollment Period G:	January 1, 2009 through December 31, 2013
Enrollment Period H:	January 1, 2010 through December 31, 2014
Enrollment Period I:	January 1, 2011 through December 31, 2015
Enrollment Period J:	January 1, 2012 through December 31, 2016
Enrollment Period K:	January 1, 2013 through December 31, 2017

SCHEDULE 489 (Continued)

MONTHLY RATE

The Monthly Rate will be the sum of the following charges at the applicable Delivery Voltage per POD*:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge	$4,850.00	$4,460.00	$5,130.00	(I)
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.90	$1.85	$1.85	
Over 4,000 kW	$1.26	$1.21	$1.21	
per kW of monthly On-Peak Demand	$2.05	$1.99	$1.12	(I)
System Usage Charge				
per kWh	0.020 ¢	0.019 ¢	0.018 ¢	(R)

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the POD.

MARKET BASED PRICING OPTION

Energy Supply

The Customer may elect to purchase Energy from an Electricity Service Supplier (ESS) (Direct Access Service) or from the Company. Such election will be for all of the Customer's POD under this schedule.

Direct Access Service

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, Transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS.

SCHEDULE 489 (Continued)

MARKET BASED PRICING OPTION (Continued)

Company Supplied Energy

Upon not less than five business days notice, the Customer may choose the Company Supplied Energy Charge option. The election of this option will be effective on the next regularly scheduled meter reading date, but with not less than a five business day notice to the Company prior to the scheduled meter read date.

The Company Supplied Energy Option is the Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Index) plus 2 mills per kWh plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported.

Wheeling Charge

The Wheeling Charge will be $1.713 per kW of monthly Demand. (I)

Transmission Charge

Transmission and Ancillary Service Charges will be as specified in the Company's Open Access Transmission Tariff (OATT) as filed and approved by the Federal Energy Regulatory Commission.

MINIMUM CHARGE

The minimum charge will be the Basic and Distribution Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher minimum charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in Facilities. The minimum Facility Capacity and Demand (in kW) will be 200 kW and 4,000 kW for primary voltage and subtransmission voltage service respectively.

ON AND OFF PEAK HOURS

On-peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

SCHEDULE 515
OUTDOOR AREA LIGHTING
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Nonresidential Customers purchasing Direct Access Service for outdoor area lighting.

CHARACTER OF SERVICE

Lighting services, which consist of the provision of Company-owned luminaires mounted on Company-owned poles, in accordance with Company specifications as to equipment, installation, maintenance and operation.

The Company will replace lamps on a scheduled basis. Subject to the Company's operating schedules and requirements, the Company will replace individual burned-out lamps as soon as reasonably possible after the Customer or Electricity Service Supplier (ESS) notifies the Company of the burn-out.

MONTHLY RATE

Rates for Area Lighting

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate(1) Per Luminaire	
Cobrahead					
Mercury Vapor	175	7,000	66	$ 9.22 (2)	(I)
	400	21,000	147	13.18 (2)	
	1,000	55,000	374	24.29 (2)	
HPS	70	6,300	30	7.70 (2)	
	100	9,500	43	8.24	
	150	16,000	62	9.13	
	200	22,000	79	10.06	
	250	29,000	102	11.26	
	310	37,000	124	12.65 (2)	
	400	50,000	163	14.41	
Flood , HPS	100	9,500	43	8.27 (2)	
	200	22,000	79	10.96 (2)	
	250	29,000	102	12.05	
	400	50,000	163	14.80	
Shoebox, HPS (bronze color, flat lens, or drop lens, multi-volt)	70	6,300	30	9.15	
	100	9,500	43	9.93	
	150	16,500	62	11.10	(I)

(1) See Schedule 100 for applicable adjustments.
(2) No new service.

SCHEDULE 515 (Continued)

MONTHLY RATE (Continued)
Rates for Area Lighting (Continued)

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate[1] Per Luminaire	
Special Acorn Type, HPS	100	9,500	43	$12.91	(I)
HADCO Victorian, HPS	150	16,500	62	13.78	
	200	22,000	79	15.32	
	250	29,000	102	16.39	
Early American Post-Top, HPS, Black	100	9,500	43	9.01	(I)
Special Types					
Cobrahead, Metal Halide	150	10,000	60	9.66	(R)
Cobrahead, Metal Halide	175	12,000	71	10.45	(I)
Flood, Metal Halide	350	30,000	139	15.15	(R)
Flood, Metal Halide	400	40,000	156	14.71	(I)
Flood, HPS	750	105,000	285	23.89	
HADCO Independence, HPS	100	9,500	43	13.04	
	150	16,000	62	13.57	
HADCO Capitol Acorn, HPS	100	9,500	43	17.02	
	150	16,000	62	17.94	
	200	22,000	79	18.58	
	250	29,000	102	19.64	
HADCO Techtra, HPS	100	9,500	43	22.16	
	150	16,000	62	22.68	(I)
	250	29,000	102	23.85	(R)
HADCO Westbrooke, HPS	70	6,300	30	15.37	
	100	9,500	43	15.72	
	150	16,000	62	16.60	
	200	22,000	79	17.66	
	250	29,000	102	18.59	(R)
KIM Archetype, HPS	250	29,000	102	21.58	(I)
	400	50,000	163	19.15	
Holophane Mongoose, HPS	150	16,000	62	14.26	
	250	29,000	102	15.38	(I)
					(D)

(1) See Schedule 100 for applicable adjustments.

SCHEDULE 515 (Continued)

MONTHLY RATE (Continued)
Rates for Area Light Poles[1]

Type of Pole	Pole Length (feet)	Monthly Rate Per Pole	
Wood, Standard	35 or less	$ 7.40	(I)
	40 to 55	9.70	(C)
Wood, Painted Underground	35 or less	7.40 [2]	
Wood, Curved laminated	30 or less	9.19 [2]	
Aluminum, Regular	16	8.86	
	25	14.70	
	30	15.89	
	35	19.02	(I)
Aluminum, Fluted Ornamental	14	12.99	(R)
Aluminum Davit	25	13.60	(I)
	30	14.60	
	35	15.97	
	40	21.68	
Aluminum Double Davit	30	21.58	(I)
Aluminum, HADCO, Fluted Ornamental	16	13.28	(R)
Aluminum, HADCO, Non-fluted	18	25.57	(I)
Concrete, Ameron Post-Top	25	25.51	(R)
Fiberglass Fluted Ornamental; Black	14	15.70	(I)
Fiberglass, Regular			
Black,	20	6.51	
Gray or Bronze;	30	11.07	
Other Colors (as available)	35	9.53	
Fiberglass, Anchor Base Gray	35	17.45	
Fiberglass, Direct Bury with Shroud	18	10.50	(I)

(1) No pole charge for luminaires placed on existing Company-owned distribution poles.
(2) No new service.

INSTALLATION CHARGE

See Schedule 300 regarding the installation of conduit on wood poles.

SCHEDULE 532
SMALL NONRESIDENTIAL
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Small Nonresidential Customers who have chosen to receive Electricity from an Electricity Service Supplier (ESS).

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge		
Single Phase	$14.00	(I)
Three Phase	$18.00	
Distribution Charge		
First 5,000 kWh	4.241 ¢ per kWh	(I)
Over 5,000 kWh	0.673 ¢ per kWh	(R)

* See Schedule 100 for applicable adjustments.

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 538
LARGE NONRESIDENTIAL OPTIONAL TIME-OF-DAY
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

This optional schedule is applicable to Large Nonresidential Customers who have chosen to receive service from an Electricity Service Supplier (ESS), and: 1) served at Secondary voltage with a monthly Demand that does not exceed 200 kW more than once in the preceding 13 months; or 2) who were receiving service on Schedule 38 as of December 31, 2006.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge			
Single Phase Service	$25.00		(I)
Three Phase Service	$25.00		
Distribution Charge	6.163	¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.

MINIMUM CHARGE

The Minimum Charge will be the Basic Charge. In Addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge if necessary, to justify the Company's investment in service facilities.

REACTIVE DEMAND

In addition to the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 549
IRRIGATION AND DRAINAGE PUMPING
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers who have chosen to receive Electricity from an Electricity Service Supplier (ESS) for irrigation and drainage pumping; may include other incidental service if an additional meter would otherwise be required.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge		
Summer Months**	$35.00	(I)
Winter Months**	No Charge	
Distribution Charge		
First 50 kWh per kW of Demand	4.248 ¢ per kWh	(I)
Over 50 kWh per kW of Demand	2.248 ¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.
** Summer Months and Winter Months commence with meter readings as defined in Rule B.

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

SCHEDULE 575
PARTIAL REQUIREMENTS SERVICE
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers who receive Electricity Service from an Electricity Service Supplier (ESS) and who supply all or some portion of their load by self generation operating on a regular basis, where the self-generation has a total nameplate rating of 2 MW or greater. A Large Nonresidential Customer is a Customer that has exceeded 30 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 30 kW.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Point of Delivery (POD)*:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge				
Three Phase Service	$4,850.00	$4,460.00	$5,130.00	(I)
Distribution Charge				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.90	$1.85	$1.85	
Over 4,000 kW	$1.26	$1.21	$1.21	
per kW of monthly On-Peak Demand**	$2.05	$1.99	$1.12	(I)
Generation Contingency Reserves Charges***				
Spinning Reserves				
per kW of Reserved Capacity > 1,000 kW	$0.234	$0.234	$0.234	
Supplemental Reserves				
per kW of Reserved Capacity > 1,000 kW	$0.234	$0.234	$0.234	
System Usage Charge				
per kWh	0.020 ¢	0.019 ¢	0.018 ¢	(R)

* See Schedule 100 for applicable adjustments.
** Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.
*** Not applicable when ESS is providing Energy Regulation and Imbalance services as described in Schedule 600.

SCHEDULE 576R
ECONOMIC REPLACEMENT POWER RIDER
DIRECT ACCESS SERVICE

PURPOSE

To provide Customers served on Schedule 575 with the option for delivery of Energy from the Customer's Electricity Service Supplier (ESS) to replace some, or all of the Customer's on-site generation when the Customer deems it is more economically beneficial than self generating.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers served on Schedule 575.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHY RATE

The following charges are in addition to applicable charges under Schedule 575:*

	Secondary	Primary	Subtransmission	
Daily Economic Replacement Power (ERP) Demand Charge				
per kW of Daily ERP Demand during On-Peak hours per day**	$0.080	$0.078	$0.044	(I)
System Usage Charge				
per kWh of ERP	0.020 ¢	0.019 ¢	0.018 ¢	(R)
Transaction Fee				
per Energy Needs Forecast (ENF) submission or revision	$50.00	$50.00	$50.00	

* See Schedule 100 for applicable adjustments.
** Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

SCHEDULE 583
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE
(31 – 200 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customers whose Demand has not exceeded 200 kW more than six times in the preceding 13 months and has not exceeded 1,000 kW more than once in the preceding 13 months, or with seven months or less of service has not had a Demand exceeding 1,000 kW and who has chosen to receive Electricity from an Electricity Service Supplier (ESS).

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Point of Delivery (POD)*:

Basic Charge		
Single Phase Service	$30.00	(I)
Three Phase Service	$40.00	
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 30 kW	$2.98	
Over 30 kW	$2.48	
per kW of monthly Demand	$2.05	
System Usage Charge		
per kWh	0.691 ¢	(I)

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the POD.

SCHEDULE 585
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE
(201 – 4,000 kW) **(C)**

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customers whose Demand has exceeded 200 kW more than six times in the preceding 13 months and has not exceeded 4,000 kW more than once in the preceding **(C)** 13 months, or with seven months or less of service has not had a Demand exceeding 4,000 kW and **(C)** who has chosen to receive Electricity from an Electricity Service Supplier (ESS).

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Point of Delivery (POD)*:

	Delivery Voltage		
	Secondary	Primary	
Basic Charge	$370.00	$390.00	(I)
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 200 kW	$3.12	$3.04	(I)
Over 200 kW	$2.12	$2.04	(R)(I)
per kW of monthly On-Peak Demand	$2.05	$1.99	(I)
System Usage Charge			
per kWh	0.042 ¢	0.040 ¢	(R)

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the POD.

SCHEDULE 589
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE
(>4,000 kW) **(C)**

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has exceeded 4,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 4,000 kW, and who has chosen to receive Electricity from an ESS. **(C)**

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Point of Delivery (POD)*:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge	$4,850.00	$4,460.00	$5,130.00	(I)
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.90	$1.85	$1.85	
Over 4,000 kW	$1.26	$1.21	$1.21	
per kW of monthly on-peak Demand	$2.05	$1.99	$1.12	(I)
System Usage Charge				
per kWh	0.020 ¢	0.019 ¢	0.018 ¢	(R)

* See Schedule 100 for applicable adjustments.
** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the POD.

SCHEDULE 591 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)
Option A - Luminaire (Continued)

The Customer is responsible for repair or replacement of luminaires and circuits damaged as a result of rotted wood poles owned by the Customer. **(N)** **(N)**

The Company may remove or discontinue service to any luminaire and related equipment that has become unsafe or unsatisfactory for further service by reason of deterioration, storm, flood, and lightning, proximity to interference by trees or structures, or other causes as determined by the Company. The Company will notify the Customer as soon as reasonably practical of any such service discontinuation and luminaire replacement schedule.

Option B - Luminaire

Option B provides electricity service to Customer purchased and owned luminaires at the monthly Option B rate applicable to the installed type of light.

The Company does not at any time assume ownership of Option B luminaires.

As defined herein, the Company provides for maintenance only to luminaires and related equipment at the applicable monthly Option B rate. The Company will replace non-repairable Option B luminaires for which the Customer is charged and billed the appropriate replacement costs (1), in addition to the applicable monthly Option B rate.

Maintenance Service under Option B

Includes preventative group lamp replacement and glassware cleaning subject to the Company's operating schedule.

Maintenance under Option B luminaires specifically does not include replacement of failed or failing ballasts or replacement of luminaires that are deemed inoperable due to general deterioration, lack of replacement parts, or replacement of parts associated with Emergency Repair that will not bring the unit into operable status. Such inoperable luminaires will be designated as non-repairable luminaires. This exclusion does not include replacements of Power Doors where the Customer is qualified and paying the applicable Cobrahead Power Door rate. In addition, Maintenance under Option B luminaires excludes maintenance related to vegetation management, luminaire relocation or modification of the luminaire (such as adding light shields).

(1) Replacement costs include: Installation Labor + Material costs and loading + Removal Labor = total billable charges. For applicable labor rates, refer to page 591-6 of this Schedule.

SCHEDULE 591 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)

Option C – Luminaire

Option C provides electricity service to luminaires that are purchased, owned and maintained by the Customer and installed on Customer-owned poles. As a condition to the election of Option C, Customer is responsible for ensuring that all new underground service installations of Option C luminaires are isolated by a disconnect switch or fuse. Both the equipment used to isolate the luminaire and its location must be approved by the Company. **(C)**

Maintenance Service under Option C

The Company does not maintain Customer-purchased lighting when mounted on Customer-owned poles. Such maintenance and service is the sole responsibility of the Customer.

Special Provisions for Option B to Option C Luminaire Conversion and Future Maintenance Election

1. The Company will, with not less than 180 days written notice from the Customer (the requesting municipality) and subject to completion of all conditions necessary to finalize such election, convert the entirety of the Customer's lighting service under Option B luminaire lighting rates to the equivalent Option C luminaires lighting rates (with respect to Monthly kWh usage) including Option B luminaires attachment to Company-owned poles.

2. Upon such conversion, the Customer will assume all on-going maintenance responsibilities for the luminaires and associated circuits in accordance with this schedule's provisions for Option C luminaires. The Customer may not require that the Company provide new Option B lighting following the conversion to Option C luminaires. The Customer must notify and inform all affected residents of the conversion that all maintenance and repair services are the sole responsibility of the Customer, and not the Company.

3. The Customer may choose the Schedule 91 Option B to Schedule 95 Option C Luminaire Conversion and Future Maintenance Election as described in Schedule 95 if converting to Schedule 95 Option C luminaires and the above notice has not been given. **(T)**

SCHEDULE 591 (Continued)

STREETLIGHT POLES SERVICE OPTIONS (Continued)
Option B – Pole maintenance (Continued)

Emergency Pole Replacement and Repair

The Company will repair or replace damaged streetlight poles that have been damaged due to the acts of vandalism, damage claim incidences and storm related events that cause a pole to become structurally unsound at no additional cost to the customer.

Without notice to the Customer, individual poles that are damaged or destroyed by unexpected events will be replaced on determination that the pole is unfit for further use as soon as reasonably possible. Replacement is subject to the Company's operating schedules and requirements.

Special Provisions for Option B - Poles

1. If damage occurs to any streetlighting pole more than two times in any 12-month period measured from the first incidence of damage that requires replacement, the Customer will be responsible to pay for future installations or mutually agree with the Company and pay to have the pole either completely removed or relocated.

2. Non-Standard or Custom poles are provided at the Company's discretion to allow greater flexibility in the choice of equipment. The Company will not maintain an inventory of this equipment and thus delays in maintenance may occur. The Company will order and replace the equipment subject to availability since non-standard and custom equipment is subject to obsolescence. The Customer will pay for any additional cost to the Company for ordering non-standard equipment.

MONTHLY RATE

The service rates for Option A and B lights include the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Distribution Charge	4.548 ¢ per kWh	(I)
Energy Charge	Provided by Energy Service Supplier	

NOVEMBER ELECTION WINDOW

The November Election Window begins at 2:00 p.m. on November 15th (or the following business day if the 15th falls on a weekend or holiday). The November Election Window will remain open until 5:00 p.m. at the close of the fifth consecutive business day.

During a November Election Window, a Customer may notify the Company of its choice to change to any service options for an effective date of January 1st. Customers may notify the Company of a choice to change service options using the Company's website, PortlandGeneral.com/business

SCHEDULE 591 (Continued)

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rates (1)	Straight Time	Overtime
	$120.00 per hour	$167.00 per hour

(1) Per Article 20.2 of the Collective Bargaining Agreement Union No. 125 Contract, overtime is paid at the Overtime Rate for a minimum of one hour.

RATES FOR STANDARD LIGHTING
High-Pressure Sodium (HPS) Only – Service Rates

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Cobrahead Power Doors **							
	70	6,300	30	*	$ 2.64	$ 1.36	(R)(I)
	100	9,500	43	*	3.25	1.96	
	150	16,000	62	*	4.12	2.82	
	200	22,000	79	*	4.95	3.59	
	250	29,000	102	*	6.01	4.64	
	400	50,000	163	*	8.80	7.41	
Cobrahead, Non-Power Door	70	6.300	30	$ 6.56	2.89	1.36	
	100	9,500	43	7.10	3.48	1.96	
	150	16,000	62	7.99	4.35	2.82	
	200	22,000	79	9.39	5.17	3.59	
	250	29,000	102	10.58	6.25	4.64	
	400	50,000	163	13.73	9.05	7.41	
Flood	250	29,000	102	11.37	6.34	4.64	
	400	50,000	163	14.13	9.10	7.41	
Early American Post-Top	100	9,500	43	7.88	3.56	1.96	
Shoebox (Bronze color, flat	70	6,300	30	8.01	3.06	1.36	
Lens, or drop lens, multi-volt)	100	9,500	43	8.79	3.68	1.96	
	150	16,000	62	9.96	4.59	2.82	(R)(I)

* Not offered.
** Service is only available to customers with total power doors luminaires in excess of 2,500.

SCHEDULE 591 (Continued)

RATES FOR STANDARD POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Fiberglass, Black	20	$ 6.51	$ 0.19	(I)
Fiberglass, Bronze	30	10.26	0.29	
Fiberglass, Gray	30	11.07	0.32	
Wood, Standard	30 to 35	7.40	0.21	
Wood, Standard	40 to 55	9.70	0.28	(I)

RATES FOR CUSTOM LIGHTING

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Acorn-Types							
HPS	100	9,500	43	$12.23	$ 4.04	$ 1.96	(R)(I)
HADCO Victorian, HPS	150	16,000	62	13.11	4.92	2.82	
	200	22,000	79	14.65	5.81	3.59	
	250	29,000	102	15.71	6.86	4.64	
HADCO Capitol Acorn, HPS	100	9,500	43	16.35	4.52	1.96	
	150	16,000	62	17.26	5.43	2.82	
	200	22,000	79	17.90	6.19	3.59	
	250	29,000	102	18.97	7.25	4.64	
Special Architectural Types							
HADCO Independence, HPS	100	9,500	43	12.36	4.04	1.96	
	150	16,000	62	12.89	4.87	2.82	
HADCO Techtra, HPS	100	9,500	43	21.48	5.10	1.96	
	150	16,000	62	22.01	5.94	2.82	
	250	29,000	102	23.17	7.72	4.64	
HADCO Westbrooke, HPS	70	6,300	30	14.70	3.79	1.36	
	100	9,500	43	15.05	4.36	1.96	
	150	16,000	62	15.92	5.23	2.82	
	200	22,000	79	16.98	6.07	3.59	
	250	29,000	102	17.91	7.11	4.64	(R)(I)

* Not offered.

SCHEDULE 591 (Continued)

RATES FOR CUSTOM LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Types							
Cobrahead, Metal Halide	150	10,000	60	$ 8.53	$ 4.57	$ 2.73	(R)(I)
Flood, Metal Halide	350	30,000	139	14.48	8.47	6.32	
Flood, HPS	750	105,000	285	23.21	15.65	12.96	
Holophane Mongoose, HPS	150	16,000	62	13.59	4.97	2.82	
	250	29,000	102	14.71	6.73	4.64	(R)(I)
							(D)
Option C Only **							
Ornamental Acorn Twin	85	9,600	64	*	*	2.91	(I)
Ornamental Acorn	55	2,800	21	*	*	0.96	
Ornamental Acorn Twin	55	5,600	42	*	*	1.91	
Composite, Twin	140	6,815	54	*	*	2.46	
	175	9,815	66	*	*	3.00	(I)

RATES FOR CUSTOM POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Aluminum, Regular	16	$ 8.86	$ 0.25	(I)(R)
	25	14.70	0.42	
	30	15.89	0.45	
	35	19.02	0.54	
Aluminum Davit	25	14.67	0.42	
	30	14.60	0.42	
	35	15.97	0.46	
	40	21.68	0.62	
Aluminum Double Davit	30	21.58	0.62	
Aluminum, HADCO, Fluted Victorian Ornamental	14	12.99	0.37	(I)

* Not offered.
** Rates are based on current kWh energy charges.

SCHEDULE 591 (Continued)

RATES FOR CUSTOM POLES (Continued)

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Aluminum, HADCO, Non-Fluted Techtra Ornamental	18	$25.57	$ 0.73	(I)
Aluminum, HADCO, Fluted Ornamental	16	13.28	0.38	
Aluminum, HADCO, Non-Fluted Ornamental Westbrooke	16	27.18	0.78	
Aluminum, HADCO, Fluted Westbrooke	18	25.64	0.73	
Aluminum, HADCO, Non-Fluted, Westbrooke	18	27.18	0.78	
Aluminum, Painted Ornamental	35	43.67	1.25	(I)
Concrete, Decorative Ameron	20	25.51	0.73	(R)
Concrete, Ameron Post-Top	25	25.51	0.73	(I)
Fiberglass, HADCO, Fluted Ornamental Black	14	15.70	0.45	
Fiberglass, Smooth	18	6.48	0.19	
Fiberglass, Regular,				
color may vary	22	5.80	0.17	
color may vary	35	9.53	0.27	
Fiberglass, Anchor Base, Gray	35	17.45	0.50	
Fiberglass, Direct Bury with Shroud	18	10.50	0.30	(I)

(D)

SERVICE RATE FOR OBSOLETE LIGHTING

The following equipment is not available for new installations under Options A and B. To the extent feasible, maintenance will be provided. Obsolete Lighting will be replaced with the Customer's choice of Standard or Custom equipment. The Customer will then be billed at the appropriate Standard or Custom rate. If an existing mercury vapor luminaire requires the replacement of a ballast, the unit will be replaced with a corresponding HPS unit.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	Monthly Rates Option C	
Cobrahead, Mercury Vapor	100	4,000	39	*	*	$ 1.77	(I)
	175	7,000	66	$ 8.08	$ 4.46	3.00	(R)(I)
	250	10,000	94	*	*	4.28	(R)(I) (I)
	400	21,000	147	12.51	8.29	6.69	
	1,000	55,000	374	23.61	18.93	17.01	(I)

* Not offered.

SCHEDULE 591 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Box Similar to GE "Space-Glo"							
HPS	70	6,300	30	$ 8.09	$ 2.98	$ 1.36	(R)
Mercury Vapor	175	7,000	66	9.68	4.57	3.00	(R)(I)
Special box, Anodized Aluminum							
Similar to GardCo Hub							
HPS	Twin 70	6,300	60	*	*	2.73	
	70	6,300	30	*	*	1.36	
	100	9,500	43	*	3.93	1.96	
	150	16,000	62	*	4.81	2.82	
	250	29,000	102	*	*	4.64	
	400	50,000	163	*	*	7.41	
Metal Halide	250	20,500	99	*	5.70	4.50	
	400	40,000	156	*	8.29	7.09	
Cobrahead, Metal Halide	175	12,000	71	9.31	4.92	3.23	
Flood, Metal Halide	400	40,000	156	14.03	8.83	7.09	
Cobrahead, Dual Wattage HPS							
70/100 Watt Ballast	100	9,500	43	*	3.49	1.96	
100/150 Watt Ballast	100	9,500	43	*	3.49	1.96	
100/150 Watt Ballast	150	16,000	62	*	4.37	2.82	
Special Architectural Types Including Philips QL Induction Lamp Systems							(M)
HADCO Victorian, QL	85	6,000	32	*	2.13	1.46	
	165	12,000	60	*	3.67	2.73	
HADCO Techtra, QL	165	12,000	60	25.95	3.87	2.73	(M)
Special Architectural Types							
KIM SBC Shoebox, HPS	150	16,000	62	*	5.37	2.82	(R)(I)
KIM Archetype, HPS	250	29,000	102	*	7.45	4.64	(I)
	400	50,000	163	*	9.61	7.41	(I)

* Not offered

SCHEDULE 591 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Acorn-Type, HPS	70	6,300	30	$11.61	$ 3.42	$ 1.36	(R)(I)
Special GardCo Bronze Alloy							
HPS	70	5,000	30	*	*	1.36	(I)
Mercury Vapor	175	7,000	66	*	*	3.00	
Special Acrylic Sphere							
Mercury Vapor	400	21,000	147	*	*	6.69	(I)
Early American Post-Top, HPS							
Black	70	6,300	30	7.17	2.85	1.36	(R)(I)
Rectangle Type	200	22,000	79	*	*	3.59	
Incandescent	92	1,000	31	*	*	1.41	
	182	2,500	62	*	*	2.82	(I)
Town and Country Post-Top							
Mercury Vapor	175	7,000	66	8.82	4.50	3.00	(R)(I)
Flood, HPS	70	6,300	30	6.56	2.94	1.36	
	100	9,500	43	7.13	3.48	1.96	
	200	22,000	79	10.28	5.25	3.59	(R)(I)
Cobrahead, HPS							
Power Door	310	37,000	124	11.97	7.64	5.64	(I)
Special Types Customer-Owned & Maintained							
Ornamental, HPS	100	9,500	43	*	*	1.96	
Twin ornamental, HPS	Twin 100	9,500	86	*	*	3.91	
Compact Fluorescent	28	N/A	12	*	*	0.55	(I)

* Not offered.

SCHEDULE 591 (Continued)

RATES FOR OBSOLETE LIGHTING POLES

Type of Pole	Poles Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Aluminum Post	30	$ 8.86	*	(I)
Bronze Alloy GardCo	12	*	$ 0.23	(R)
Concrete, Ornamental	35 or less	14.70	0.42	
Steel, Painted Regular **	25	14.70	0.42	
Steel, Painted Regular **	30	15.89	0.45	
Steel, Unpainted 6-foot Mast Arm **	30	*	0.42	
Steel, Unpainted 6-foot Davit Arm **	30	*	0.42	
Steel, Unpainted 8-foot Mast Arm **	35	*	0.46	
Steel, Unpainted 8-foot Davit Arm **	35	*	0.46	
Wood, Laminated without Mast Arm	20	6.51	0.19	
Wood, Laminated Street Light Only	20	6.51	*	
Wood, Curved Laminated	30	10.26	0.29	
Wood, Painted Underground	35	7.40	0.21	
Wood, Painted Street Light Only	35	7.40	*	(I)

* Not offered.
** Maintenance does not include replacement of rusted steel poles. (D)
(M)

SCHEDULE 591 (Continued)

SPECIAL CONDITIONS (Continued)

5. If circuits or poles not already covered under Special Condition 2 or 3 are removed or relocated at the Customer's request, the Customer is responsible for all associated costs for labor and materials incurred when fulfilling this request.

6. For Option C lights: The Company does not provide the circuit on new installations. **(C)**

7. For Option C lights in service prior to January 31, 2006: When the Company furnishes Electricity to luminaires owned and maintained by the Customer and installed on Customer-owned poles that are not included in the list of equipment in this schedule, usage for the luminaire will be estimated by the Company. When the Customer and the Company cannot agree, the Commission will determine the estimate usage.

8. For Option A and Option B lights: The Company shall not be liable when either (i) the luminaires become inoperable or (ii) repair or replacement of inoperable luminaires is delayed or prevented; provided that, such inoperability of the luminaires or delay or prevention of repair or replacement is due to any cause beyond the Company's control, or that otherwise could not reasonably be foreseen or guarded against including but not limited to such causes as: strikes, lockouts, labor troubles, riots, insurrection, war, acts of God, extreme weather conditions, access to equipment, or the like.

9. For Option C lights: The Customer must ensure that (i) all maintenance and other work associated with this schedule is in compliance with the applicable requirements of OSHA, OPUC Safety Rules, the NESC and/or NEC and (ii) that all such work is performed by a Qualified Worker. A "Qualified Worker" means one who is knowledgeable about the construction and operation of the electric power generation, transmission, and distribution equipment as it relates to his or her work, along with the associated hazards, as demonstrated by satisfying the qualifying requirements for a "qualified person" or "qualified employee" with regard to the work in question as described in 29 CFR 1910.269 effective January 31, 1994, as it may be amended from time to time. In this case, a Qualified Worker is a journeyman lineman, or someone who has the equivalent training, expertise and experience to perform journeyman lineman work.

SCHEDULE 592
TRAFFIC SIGNALS
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments served on Schedule 92, who purchase Electricity from an Electricity Service Supplier (ESS) for traffic signals and warning facilities in systems containing at least 50 intersections on public streets and highways, where funds for payment of Electricity are provided through taxation or property assessment. This schedule is available only to those governmental agencies receiving service under Schedule 92 as of September 30, 2001.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The charge per Point of Delivery (POD)* is:

Distribution Charge	2.078 ¢ per kWh	(R)

* See Schedule 100 for applicable adjustments.

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 595
STREET AND HIGHWAY LIGHTING
NEW TECHNOLOGY
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments purchasing Direct Access for lighting service utilizing Company approved streetlighting equipment for public streets and highways and public grounds where funds for payment of Electricity are provided through taxation or property assessment.

CHARACTER OF SERVICE

From dusk to dawn daily, controlled by a photoelectric control to be mutually agreeable to the Customer and Company for an average of 4,100 hours annually.

LUMINAIRE SERVICE OPTIONS - The Company offers the following Luminaire Service Options at the applicable rates specified herein.

The Customer will elect the Luminaire Service Option at the time of initial luminaire installation.

Option A - Luminaire

Option A provides electricity service to luminaires that are purchased, owned, and maintained by the Company with attachment to Company-owned poles at the monthly Option A rate applicable to the installed type of light.

Maintenance Service under Option A

The Company will only perform emergency maintenance on the luminaires listed in this schedule. The Company does not perform preventative maintenance on the luminaires listed in this schedule.

The Company will repair or replace inoperable luminaires as soon as reasonably possible, subject to the Company's operating schedule, following notification to PGE's Customer Service or PGE's Outdoor Lighting Services[1] department by the Customer, a member of the public, or a PGE employee performing luminaire replacement work. PGE has no obligation for repair or replacement of inoperable luminaires other than as described in this section of the tariff. (C)

(1) Contact PGE's Outdoor Lighting Services at 503-736-5710, PGE's Customer Service 503-228-6322 or 1- 800-542-8818, or www.portlandgeneral.com to report an inoperable streetlight.

SCHEDULE 595 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)
Maintenance Service under Option A (Continued)

The Customer is responsible for repair or replacement of luminaires and circuits damaged as a result of rotted wood poles owned by the Customer. (N) (N)

The Company may remove or discontinue service to any luminaire and related equipment that has become unsafe or unsatisfactory for further service by reason of deterioration, storm, flood, and lightning, proximity to interference by trees or structures, or other causes as determined by the Company. The Company will notify the Customer as soon as reasonably practical of any such service discontinuation.

Option C – Luminaire

Option C provides electricity service to luminaires that are purchased, owned and maintained by the Customer and installed on Customer-owned poles. As a condition to the election of Option C, Customer is responsible for ensuring that all new underground service installations of Option C luminaires are isolated by a disconnect switch or fuse. Both the equipment used to isolate the luminaire and its location must be approved by the Company. The Company may provide necessary circuits for an additional charge.

Maintenance Service under Option C

The Company has no obligation to maintain Customer-purchased lighting if the Customer selects this option. Such maintenance and service is the sole responsibility of the Customer.

Special Provisions for Schedule 91/591 Option B to Schedule 95/595 Option C Luminaire Conversion and Future Maintenance Election

1. If Customer elects to convert any of its luminaires from Schedule 91 Option B to Schedule 95 Option C, the Customer must at the same time commit to convert the entirety of Customer's Schedule 91 Option B luminaires to Schedules 91 Option C and Schedule 95 Option C using one of two methods: (A) within five years following PGE's group lamp replacement cycle or (B) within three years on a schedule mutually agreed upon between the Company and Customer. Customer may elect to have some of its luminaires on Schedule 91 Option C and some on Schedule 95 Option C.

2. Upon such conversion, the Customer will assume and bear the cost of all on-going maintenance responsibilities for the luminaires and associated circuits in accordance with this schedule's provisions for Option C luminaires from the date each luminaire is converted to Option C. After the three or five year period, any remaining Option B luminaires will be converted to Option C. The Company may not provide new Option B lighting under Schedule 91 following the election to convert any Option B luminaires to Schedule 91 or Schedule 95 Option C luminaires.

SCHEDULE 595 (Continued)

STREETLIGHT POLES SERVICE OPTIONS

Option A – Poles

See Schedule 91/591 for Streetlight poles service options.

MONTHLY RATE

The service rates for Option A lights include the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Distribution Charge 4.548 ¢ per kWh (I)

Energy Charge Provided by Energy Service Supplier

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rates [(1)]	Straight Time	Overtime
	$120.00 per hour	$167.00 per hour

(1) Per Article 20.2 of the Collective Bargaining Agreement Union No. 125 Contract, overtime is paid at the Overtime Rate for a minimum of one hour.

RATES FOR STANDARD LIGHTING

Light-Emitting Diode (LED) Only – Option A Service Rates

LED lighting is new to the Company and pricing is changing rapidly. The Company may adjust rates under this schedule based on actual frequency of maintenance occurrences and changes in material prices.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rate Option A	
LED	37	2,530	13	$4.05	(R)
LED	50	3,162	17	4.23	
LED	52	3,757	18	4.70	
LED	67	5,050	23	5.41	
LED	106	7,444	36	6.86	(R)

SCHEDULE 595 (Continued)

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

NOVEMBER ELECTION WINDOW

The November Election Window begins at 2:00 p.m. on November 15th (or the following business day if the 15th falls on a weekend or holiday). The November Election Window will remain open until 5:00 p.m. at the close of the fifth consecutive business day.

During a November Election Window, a Customer may notify the Company of its choice to change to any service options for an effective date of January 1st. Customers may notify the Company of a choice to change service options using the Company's website, PortlandGeneral.com/business

SPECIAL CONDITIONS

1. The Company may periodically offer temporary or experimental lighting equipment that is not otherwise listed in this rate schedule. Temporary or experimental lighting will be offered at a billing rate based on approved prices for near equivalent lighting service equipment. The use of temporary or experimental lighting will be for a limited duration not to exceed one year at which time the lighting service equipment will either be removed or the Company will file with the Commission to add the luminaire type to this rate schedule.

2. Customer is responsible for the cost associated with trenching, boring, conduit and restoration required for underground service to streetlighting.

3. Unless otherwise specifically provided, the location of Company-owned streetlighting equipment and poles may be changed at the Customer's request and upon payment by the Customer of the costs of removal and reinstallation.

4. If Company-owned streetlighting equipment or poles are removed at the Customer's request, a charge will be made consisting of the estimated original cost, less depreciation, less salvage value, plus removal cost. This provision does not pertain to the sale of Company-owned equipment. This condition applies if a Customer's selection of service under this Schedule requires the removal of Company-owned streetlighting equipment or poles.

5. If circuits or poles not already covered under Special Condition 2 or 3 are removed or relocated at the Customer's request, the Customer is responsible for all associated costs for labor and materials incurred when fulfilling this request.

6. For Option C lights: The Company does not provide the circuit on new installations. **(C)**

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 262

General Rate Case Filing
For Prices Effective January 1, 2014

PORTLAND GENERAL ELECTRIC COMPANY

ACRONYMS

February 15, 2013

UE 262 PGE ACRONYMS

4-CP or 4-Coincident Peak – The monthly peak hours contained in the months of January, July, August, and December
A&G – Administrative and General
A/P – Accounts Payable
ACC – Arizona Corporation Commission
ACH – Automated Clearing House
ACI – Annual Cash Incentive
AFDC – Allowance for Funds Used during Construction
AMI – Advance Metering Infrastructure
ARM – Asset and Resource Management
ASC – Accounting Standards Codification
AUT – Annual Update Tariff
AUT – Annual Update Tariff
BART – Best Available Retrofit Technology
BES – Bulk Electric System
BPA – Bonneville Power Administration
BVPS – Book Value per Share
CBA – Collective Bargaining Agreement
CCCT – Combined Cycle Combustion Turbine
CEO – Chief Executive Officer
CET – Customer Engagement Transformation
CET – Customer Engagement Transformation
CFA – Chartered Financial Analyst
CFO – Chief Financial Officer
CGA – Common Ground Alliance
CIAC – Contributions in Aid of Construction
CIO – Customer Impact Offset
CIP – Critical Infrastructure Protection
CIP – Critical Infrastructure Protection
CIS – Customer Information System
COP – City of Portland
COS – Cost of Service
CPP – Critical Peak Pricing
CRG – Capital Review Group
CRRA – Certified Rate of Return Analyst
CRSP – Center for Research in Security Prices
CS&BD – Customer Strategies and Business Development
CSI – Centralization, Standardization and Integration
CV – Coefficients of Variation
CWIP – Construction Work in Progress
D&O – Directors and Officers
DCF – Discounted Cash Flow
DEQ – Department of Environmental Quality
DEQ – Department of Environmental Quality
DOE – Department of Energy
DP – Dynamic Programming

DPS – Dividends per Share
DRA – Division of Ratepayer Advocates
DSI – Dry Sorbent Injection
DSI – Dry Sorbent Injection
EDD – Employment Development Department
EDI – Electronic Data Interchange
EE – Energy Efficiency
EFSC – Energy Facility Siting Council
EMS – Energy Management System
EN – Energy Network
EPA – Environmental Protection Agency
EPS – Earnings per Share
ERISA – Employee Retirement Income Security Act
ERP – Equity Risk Premium
ES – Environmental Service
ESS – Energy Service Supplier
ETO – Energy Trust of Oregon
EV – Electric Vehicle
F&A – Finance and Accounting
FAS – Financial Accounting Standards
FERC – Federal Energy Regulatory Commission
FERC – Federal Energy Regulatory Commission
FICA – Federal Insurance Contributions Act
FITNES – Facility Inspections and Treatment to the National Electric Safety Code
FS – Feasibility Study
FSEC – Financial Systems Effectiveness Committee
FSRP – Financial System Replacement Project
FSRP – Financial Systems Replacement Project
FTE – Full Time Equivalent
FTE – Full-Time Equivalent
GAAP – Generally Accepted Accounting Principles
GAWE – Guaranteed Availability and Warranty Extension
GDP – Gross Domestic Product
GF – General Foreman
GH – Garrad Hassan America
GIS – Geographic Information System
GIS – Geospatial Information System
GWD – Graphic Work Design
GWD – Graphic Work Design
HP/IP – High Pressure and Intermediate Pressure turbine
HPS – High pressure sodium
HR – Human Resources
HRA – Health Reimbursement Account
I&C – Instrument and Control
IBEW – International Brotherhood of Electrical Workers
IRP – Integrated Resource Plan

ISFSI – Independent Spent Fuel Storage Installation
IT – Information Technology
IT – Information Technology
ITC – Investment Tax Credits
IVR – Interactive Voice Response
kW - Kilowatt
kWh – Kilowatt hours
kV – Kilovolt
kvar – Kilovolt ampere reactive
LEA – Line Extension Allowance
LED – Light-emitting diode
LRRA – Lost Revenue Recovery Adjustment
LTSA – Long-term Service Agreement
MAIFI – Momentary Average Interruption Frequency Index
MAP-21 – Moving Ahead for Progress in the 21st Century Act
MDCP – Managers Deferred Compensation Plan
MDMS – Meter Data Management System
MFRs – Minimum Filing Requirements
Mid-C – Mid-Columbia
MONET – Multi-area Optimization Network Energy Transaction model
MPPS – Market Price per Share
MSI – Market Strategies International
MWa – Megawatt average
MWh – Megawatt hours
NAICS – North America Industry Classification System
NCP – Non-coincident peak
NDT – Nuclear Decommissioning Trust
NEPA – National Environmental Policy Act
NERC – North American Electric Reliability Corporation
NERC – North American Electric Reliability Corporation
NIST – National Institute of Standards and Technology
NRC – Nuclear Regulatory Commission
NVPC – Net Variable Power Cost
NVPC – Net Variable Power Costs
O&M – Operations and Maintenance
O&M – Operations and Maintenance
OATT – Open Access Transmission Tariff
OATT – Open Access Transmission Tariff
OBI – Oracle Business Intelligence
OEA – Office of Economic Analysts
OMS – Outage Management System
OMS – Outage Management System
OSHA – Occupational Safety and Health Administration
PAS – Publicly Available Specification
PCAM – Power Cost Adjustment Mechanism
PCAM – Power Cost Adjustment Mechanism

PEG – Pacific Economics Group
PG&E – Pacific Gas and Electric
PGE – Portland General Electric
PIC – Performance Incentive Compensation
PNCA – Pacific Northwest Coordination Agreement
PPA – Pension Protection Act
PPA – Power Purchase Agreement
PPC – Public Purpose Charges
PRPs – Potentially Responsible Parties
PSC – Portland Service Center
PSES – Power Supply Engineering Services
PwC – Price Waterhouse Coopers
R&D – Research and Development
R&ME – Reliability and Maintenance Excellence
R&ME – Reliability and Maintenance Excellence
RCM – Reliability Centered Maintenance
RCM – Reliability Centered Maintenance
RE – Regional Entity
RES – Renewable Energy Standard
RFP – Request for Proposal
RFP – Request for Proposals
RI – Remedial Investigation
ROE – Return on Equity
RROE – Required Return on Equity
RP – Risk Premium
RPS – Renewable Portfolio Standard
RRMP – Recreation Resources Management Plan
RSP – Retirement Savings Plan
S&P – Standard & Poor's
SAIDI – System Average Interruption Duration Index
SAIFI – System Average Interruption Frequency Index
SB – Senate Bill
SCADA – Supervisory Control and Data Acquisition
SCCT – Simple Cycle Combustion Turbine
SEC – Securities Exchange Commission
SEDC – Safe and Efficient Design Construction
SERP – Supplemental Executive Retirement Plan
SF6 – Sulfur Hexafluoride
SHARP – Safety and Health Achievement Recognition Program
SIP – Strategic Investment Program
SITF – Supervisor in the Field
SMA – Service and Maintenance Agreement
SNA – Sales Normalization Adjustment
SQM – Service Quality Measure
T&D – Transmission and Distribution
T&D – Transmission and Distribution

TCC – Tualatin Contact Center
TCS – Time Collection System
TIV – Total Insured Value
TOU – Time-of-Use
TQS – TQS Research, Inc.
TSA – Turbine Supply Agreements
UAM – Utility Asset Management
UG – Underground
USFS – United States Forest Service
USWC – US West Communications
V2H – Vehicle to Home Concept
VIE – Variable Interest Entities
VoIP – Voice over Internet Protocol
VPP – Voluntary Protection Program
W&S – Wages and Salaries
WECC – Western Energy Coordinating Council
WMS – Work Management System
WSATA – Western States Association of Tax Administrators

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 262

General Rate Case Filing
For Prices Effective January 1, 2014

PORTLAND GENERAL ELECTRIC COMPANY

Executive Summary

February 15, 2013

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 262

In the Matter of	)	
	)	**EXECUTIVE SUMMARY OF**
PORTLAND GENERAL ELECTRIC	)	**PORTLAND GENERAL**
COMPANY	)	**ELECTRIC COMPANY**
	)	
Request for a General Rate Revision	)	

I. INTRODUCTION

Portland General Electric Company ("PGE") is an electric company and public utility pursuant to ORS 757.005. The Public Utility Commission of Oregon has jurisdiction over the price and terms of service for PGE's customers. PGE is filing this request to revise its tariff schedules pursuant to ORS 757.205 and ORS 757.220. This executive summary is submitted to meet the requirements of OAR 860-022-0019.

The revised prices reflect an overall increase in revenue requirement of $104.8 million, or 6.2% relative to currently approved base rates. The request is for a base rate increase of $102.5 million plus an additional $2.3 million that would otherwise be recovered under tariff Schedule 145. It has been three years since PGE's last general rate case. That previous case, Docket UE 215, used a 2011 test-year, and revised rates were effective January 1, 2011. PGE's cost of service prices have declined each of the last two years such that the requested increase in this docket is roughly 3.5% over those approved in UE 215.

PGE has managed cost increases during the past three years in part through enhanced use of technology and changes to work processes that reduce costs. Cost reduction has been a high priority of the company and its management, and has produced significant results. A formal benchmarking program has been implemented across the company. The results, discussed in the applicable pieces of testimony in this docket, have been mostly positive with respect to performance. In a number of areas the benchmarking results show PGE as very effective in providing service. However, in some areas the results show where PGE has been less efficient than top performers. The result is an ongoing process to identify and implement changes across the company to increase both effectiveness and efficiency.

Many of the efficiencies and cost reductions are discussed in PGE's testimony in this docket. These efforts have helped PGE to delay the filing of a rate case in the face of rising costs. However, in order to continue to provide safe, reliable electric service to customers now and in the future, and meet the other expectations of our customers and regulators, a modest price increase is necessary. Jim Piro, PGE's President and Chief Executive Officer, addresses this in his testimony in this docket.

Mr. Piro's testimony also addresses some of the specific cost drivers for PGE's request. Mr. Piro discusses the budgeting process undertaken by PGE, consistent with the company's obligation to meet our customers' expectations for service quality, reliability, regulatory compliance and safety. Mr. Piro also discusses the benchmarking process that has been implemented across PGE, some of the efficiencies that have been captured, and future plans to continue using benchmarking and other methods to continue to refine PGE's business practices and systems to achieve further efficiencies.

Exhibit 200, the testimony of Maria Pope, PGE's Chief Financial Officer and Treasurer, and Tamara Neitzke, Director of Corporate Planning and Performance Management, further describes PGE's numerous specific efficiency improvements throughout the company, and future plans for improving corporate performance. They identify specific cost savings over $10 million incorporated into this rate case.

As described below, thirteen other pieces of testimony discuss the functional areas of the company. The witnesses are all, with the exception of the witness on the appropriate return on equity, PGE officers and employees. The testimony discusses the cost drivers in each area and the projected 2014 costs incorporated into this case.

II. SUMMARY OF THIS CASE

This case is based on a normalized future test period of calendar year 2014. 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, 2014.

In this general rate case PGE requests an overall price increase of 6.2% effective January 1, 2014. The increase in revenue over what would be expected under current prices is about $104.8 million.

PGE requests an authorized ROE of 10%. The projected test year results show that, without a price increase, PGE will earn an ROE of approximately 6.2%. That is significantly below PGE's currently authorized ROE, and below the level needed to maintain PGE's credit and attract capital.

As set out in the testimony in this docket, cost increases require revised prices and schedules to meet our customers' needs for reasonable services and PGE's need for the opportunity to earn a return on invested capital that is commensurate with similar companies, allowing it to maintain its credit and attract capital on terms that will ultimately be beneficial to customers.

The submitted testimony, described below, addresses costs in each area of the company, and supports PGE's request.

Net Variable Power Costs. Each year under Schedule 125, PGE's rates are adjusted to reflect projected net variable power costs ("NVPC") for the coming year, and transition charges or credits for those customers opting for an alternate electricity supplier are calculated. Schedule 125 requires PGE to file estimates of the adjustments on or before April 1. In addition to the

NVPC forecast and Minimum Filing Requirements ("MFRs") with this filing, PGE intends to file an update, with additional MFR documentation, by April 1. PGE requests a schedule that will allow for a Commission decision of NVPC issues by mid-October consistent with the requirements of PGE's Tariff Schedules 125 and 128, and the November 2013 open access window.

Compliance with OAR 860-022-0019. Attached as Exhibit 1 is the information required by OAR 860-022-0019. That exhibit shows the impact of the proposed price change on each customer class. The impact of the requested price change on residential customers is 8.7%. The increase for an average residential customer using 900 kWh per month is 9.3% (including the impact of other adjustments such as the RPA Exchange Credit).

III. TESTIMONY

PGE's testimony and exhibits demonstrate that the Commission should approve this Application. The rates and tariffs proposed result in prices that are just and reasonable. PGE is introducing fifteen pieces of testimony sponsored by the following witnesses:

EXHIBIT NO.	TITLE	WITNESSES
100	Policy	Jim Piro
200	Corporate Performance and Efficiency	Maria Pope and Tamara Neitzke
300	Revenue Requirements	Alex Tooman and Chris Liddle
400	Net Variable Power Costs	Mike Niman and Terri Peschka
500	Compensation	Arleen Barnett, Joyce Bell and Jardon Jaramillo

600	Information Technology	Cam Henderson and Behzad Hosseini
700	Production O&M	Steve Quennoz and David Weitzel
800	Transmission and Distribution	Bill Nicholson and Bruce Carpenter
900	Customer Service	Kristin Stathis and Carol Dillin
1000	Corporate Support	Maria Pope and Alex Tooman
1100	Cost of Capital	Patrick Hager and William Valach
1200	Return on Equity	Thomas Zepp
1300	Load Forecast	Ham Nguyen and Sarah Dammen
1400	Rate Spread	Bonnie Gariety, Rob Macfarlane and Bruce Warner
1500	Pricing	Marc Cody and Rob Macfarlane

IV. SUMMARY OF TESTIMONY

Exhibit 100. Jim Piro presents the opening testimony. Mr. Piro explains the business context for this filing, describes how PGE's proposals help PGE meet customer expectations, meet required standards, lay the groundwork for sustained service quality, and explains PGE's focus on efficiency including a rigorous benchmarking process. Mr. Piro also identifies certain policy issues and recommendations. Mr. Piro also identifies and briefly discusses a number of policy issues in this docket including the continuation and modification of the storm deferral accrual implemented in Docket UE 215, implementation of a balancing account for pension-related costs, and implementation of a major maintenance accrual for Port Westward similar to

the one in place for Coyote Springs. Mr. Piro further requests and recommends the continuation of the decoupling mechanism. Mr. Piro also introduces the other testimony in this docket.

Exhibit 200. Maria Pope and Tamara Neitzke address PGE's improvement efforts and commitment to efficiency. They highlight improvement efforts undertaken throughout the company. They also identify other testimony that provides further details of efficiency improvements in certain areas of the company.

Exhibit 300. Alex Tooman and Chris Liddle summarize the overall revenue requirement of $1,787.5 million. Messrs. Tooman and Liddle explain that PGE is using a 2014 test year, and compare the request with the Commission approved revenue requirement and 2011 actual results. PGE's unbundled revenue requirement is also presented.

This testimony further contains PGE's request for continuation and modification of the storm cost accrual adopted in UE 215. Messrs. Tooman and Liddle also present PGE's request for a major maintenance accrual for Port Westward similar to the accrual in place for Coyote Springs. These witnesses also introduce the balancing account mechanism proposed by PGE regarding pension expense and a return on prepaid pension assets. This proposal is addressed more fully in Exhibit 500.

Exhibit 400. Mike Niman and Terri Peschka present PGE's Net Variable Power Costs. The initial NVPC forecast for 2014 is $639 million. This is a decrease of about $0.87 per MWh, from the 2013 NVPC determined in PGE's recent Annual Update Tariff proceeding, Docket UE 250. This testimony also addresses certain updates and modeling changes to PGE's Monet power cost model proposed in this docket to provide for more accurate power cost forecasting.

As stated above, PGE requests that a schedule be implemented in this docket to allow for a Commission decision of NVPC issues by mid-October consistent with the requirements of PGE's Tariff Schedules 125 and 128, and the November 2013 open access window.

Exhibit 500. Arleen Barnett, Joyce Bell and Jardon Jaramillo testify on compensation and human resource issues. They describe the significant changes that have occurred in this area since 2011. They explain PGE's practice of setting total compensation to the market median. Total compensation in the 2014 test year is approximately $316.4 million. Increased compensation costs are primarily driven by benefits, particularly pension and health care costs. In part due to the efficiency efforts across the company, FTEs have remained virtually flat compared to 2011.

The witnesses also discuss the particular challenges PGE faces in this area. In addition to rising health care costs, these challenges include difficulty recruiting skilled employees for certain positions and PGE's experienced but aging workforce.

In addition, these witnesses address PGE's pension plan and expenses, and the significant challenges caused by recent market performance and legal funding requirements. This testimony contains a proposal to more accurately reflect PGE's pension expense and reduce customer price volatility for pension costs.

Exhibit 600. Cam Henderson and Behzad Hosseini explain the costs associated with PGE's Information Technology ("IT") function. Many of the efficiency measures throughout the company have an IT component, adding to IT costs. This testimony provides an update on PGE's 2020 Vision project and provides the details of the drivers of cost changes in IT, including significant cost efficiencies and controls that have been obtained. PGE's plan and costs to comply with the requirements of Critical Infrastructure Protection standards issued by NERC.

Exhibit 700. PGE's long-term power supply resources and associated costs are presented by Steve Quennoz and David Weitzel. They provide information regarding the excellent plant performance PGE has experienced in recent years, efforts to reduce emissions and related costs, and efficiencies achieved. These witnesses also provide support for the proposed major maintenance accrual for Port Westward.

Exhibit 800. Bill Nicholson and Bruce Carpenter testify regarding PGE's transmission and distribution ("T&D") system. They explain the test-year operational and capital costs necessary to provide service. The testimony includes details about PGE's T&D transformation project designed to improve customer service, reliability and efficiency.

Exhibit 900. Kristin Stathis and Carol Dillin address PGE's Customer Services functions and costs for 2014. The areas covered in the customer service testimony account for most interactions with retail customers. The testimony discusses the major drivers of cost changes in this area including the Customer Engagement Transformation project, a multi-year initiative to improve customer service, capture efficiencies, and replace outdated systems. Ms. Stathis and Ms. Dillin also present PGE's proposal to allow credit card payment by customers with no fee. The costs and benefits of that proposal are discussed. This testimony also contains PGE's projected uncollectible rate for 2014.

Exhibit 1000. Maria Pope and Alex Tooman address PGE's administrative and general ("A&G") expenses. Test year A&G expenses are approximately $156.8 million. This represents a 3.1% annual change from 2011 actual A&G expenses. The testimony addresses the main drivers for cost changes, as well as cost reductions and efficiency measures implemented in this area

Exhibit 1100. Patrick Hager and William Valach present PGE's testimony on cost of capital and capital structure for 2014. On behalf of PGE, these witnesses request an 7.863% cost of capital for PGE. This includes an ROE of 10.0% and long-term debt cost of 5.726%. The witnesses address the impact of the Commission's decision regarding return on equity on PGE's credit quality and the future cost of raising capital.

These witnesses also address PGE's current and proposed test-year capital structure. In this docket PGE proposes the same capital structure for ratemaking as was used in UE 215, 50% equity and 50% debt. Finally, the witnesses address some of the specific risks PGE encounters that are relevant to PGE's cost of capital and to the appropriate return on equity to be used in this docket.

Exhibit 1200. Thomas M. Zepp addresses PGE's equity costs. Dr. Zepp addresses the risks PGE faces compared to the cost of common equity that faces a typical electric utility. Dr. Zepp addresses the effect of the economy on the ROE required to adequately raise capital. Relying on Discounted Cash Flow and Risk Premium models, recently earned and authorized ROEs, and the risks specific to PGE's cost of equity, Dr. Zepp concludes that PGE's required return on equity falls in a range of 10.0% to 10.7%, with a recommendation that PGE's authorized ROE be no less than 10%.

Exhibit 1300. Ham Nguyen and Sarah Dammen present PGE's load forecast for 2014. They forecast that total retail loads will increase only slightly from 2012 on a weather-adjusted basis. PGE will update the load forecast during this case as more information becomes available.

Exhibit 1400. Bonnie Gariety, Rob Macfarlane and Bruce Werner present PGE's marginal cost study. That study is then used as a basis for rate spread, rate design, and proposed

prices in this docket, as explained in Exhibit 1500.

Exhibit 1500. Marc Cody and Rob Macfarlane testify on pricing. They present PGE's proposed prices based on the marginal cost study. These witnesses discuss proposed changes to the residential basic charge, and Schedule 83 (adopting mandatory time-of-use rates). This testimony also presents proposed changes to tariff schedules 123 (continuing the Decoupling Adjustment), 125 (the Annual Power Cost Update), 126 (Annual Power Cost Variance Mechanism), and schedule 145 (the Boardman Power Plant Operating Life Adjustment).

V. COMMUNICATIONS

PGE requests that communications regarding this filing be addressed to:

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VI. REQUEST FOR APPROVALS

PGE requests that the Commission issue an order:

(1) Approving the requested rate changes;

(2) Approving the proposed tariffs; and

(3) Approving the requested accounting orders and ratemaking mechanisms identified in the testimony including:

i. Continuation and modification of the storm deferral accrual;

ii. The balancing account mechanism discussed in PGE Exhibit 500 that includes pension expense and a return on its prepaid pension asset;

iii. A major maintenance accrual for the Port Westward plant; and

iv. Making PGE's Schedule 123 decoupling adjustment permanent.

Dated: this 15th day of February, 2013.

Respectfully submitted,

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Exhibit 1

Case Summary
($000)

Total Revenue Requirement	$1,787,535
Change in Revenues Requested	
Total Change in Revenues Requested	$104,790
Total Change net of RPA	$104,790
Percent Change in Base Revenues Requested	6.2%
Percent Change net of RPA	6.5%
Test Period	2014
Requested Rate of Return on Capital (Rate Base)	7.863%
Requested Rate of Return on Common Equity	10.0%
Proposed Rate Base	$3,126,153
Results of Operation	
A. Before Price Change	
Utility Operating Income	$186,182
Average Rate Base	$3,124,446
Rate of Return on Capital	5.959%
Rate of Return on Common Equity	6.192%
B. After Price Change	
Utility Operating Income	$245,809
Average Rate Base	$3,126,153
Rate of Return on Capital	7.863%
Rate of Return on Common Equity	10.0%
Base Rate Effect of Proposed Price Change	
A. Residential Customers	8.7%
B. Small Non-residential Customers	10.7%
C. Large Non-residential Customers	3.3%
D. Lighting & Signal Customers	6.3%
Note: Percent Changes are on a cycle basis for Cost of Service Customers	

CERTIFICATE OF SERVICE

I hereby certify that I served **ADVICE NO. 13-03 PORTLAND GENERAL ELECTRIC GENERAL RATE REVISION UE 262,** by electronic mail to those parties whose email addresses appear on the attached service list for OPUC Docket No. UE 215.

DATED at Portland, Oregon, this 15th day of February, 2013.

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BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 262

General Rate Case Filing
For Prices Effective January 1, 2014

PORTLAND GENERAL ELECTRIC COMPANY

DIRECT TESTIMONY AND EXHIBITS

February 15, 2013

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 262

Policy

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Jim Piro

February 15, 2013

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I. Introduction and Overview

Q. Please state your name and position with Portland General Electric ("PGE").

A. My name is James J. Piro. I am the President and Chief Executive Officer for PGE. My qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to:

- Explain the business context and reasoning for this filing;
- Discuss how our proposals help PGE meet customer expectations, achieve mandatory standards and lay groundwork for sustained service quality in the future;
- Explain PGE's focus on efficiency and cost effectiveness with emphasis on PGE's benchmarking cycle; and
- Identify policy issues and explain our policy recommendations.

My testimony is organized according to these objectives.

Q. What is the business context for this rate case filing?

A. Our core focus is on providing the safe, reliable, reasonably-priced, adequate electricity our customers need to live their daily lives. To accomplish this objective, we need to meet customers' expectations. Our customers do not just expect us to seamlessly provide them with energy; they also expect us to be easy to do business with, and provide helpful and knowledgeable service. Our customers expect us to make thoughtful investments, operate prudently, think ahead to anticipate their needs and changing operational necessities, and meet all applicable regulatory standards.

To support our ability to keep providing value to customers, we must also meet the needs and expectations of three other key stakeholder groups: the community, our employees and our investors. The people and businesses we serve expect us to be a good corporate citizen, invest in the community, and model our community's values. Our employees expect us to provide challenging, engaging work, a safe, healthy work environment, and fair compensation. Our shareholders expect a competitive return on their investment. All our stakeholders expect us to operate the business in compliance with all appropriate regulatory and governance standards.

Q. What are your goals for PGE?

A. I want PGE to provide safe, reliable, adequate and reasonably-priced electricity to our customers; play an outstanding role in our community; be a desirable place for our employees to work; and offer a solid, stable investment for our investors. In an ever-changing, competitive environment, no company can afford to stand still. After all, our residential customers have a choice of where to live and our business customers – key job-creators that compete in the global marketplace – have a choice of where to do business, and they compare our service with that of other utilities across the continent and the globe when making that decision.

Q. You refer to a competitive environment, yet PGE is a regulated monopoly. Please explain.

A. Our regulated monopoly status means we are the provider of last resort for safe, reliable, adequate electricity to customers in our service territory. Within that context, however, we compete for investment capital, highly-skilled employees, and customers who have other options. Our customers have competing options in the marketplace, whether it's an energy service supplier, another fuel source, their own generation installation, or creating a publicly-owned or cooperative utility. In fact, as energy is increasingly thought of as a fundamental necessity and key to business success, customers expect even more responsiveness from us and customer service comparable to what they experience from any other business they interact with.

Q. Why are you filing this rate case?

A. We are filing this rate case to meet our customers' needs and expectations, both now and as they change going forward. Over the past three years, we have managed operational cost increases by harnessing technology and changing our work processes to create efficiencies and reduce costs. As a result we have been able to avoid filing a rate case since 2010 (2011 test year). This was done during a time when prices were increasing for many other businesses, government bureaus and utilities across our region.

In a strong economy, the increased revenues from retail load growth help offset some operational cost inflation. However, the weak economic recovery has meant that load isn't growing enough to cover increases in our operational costs. In fact, our forecasted 2014 kWh deliveries (load) are slightly down from 2012 actual deliveries. More detail on loads is contained in PGE Exhibit 1300. We are operating in an environment where, rather than promoting load growth to moderate impacts on customer prices, we are working hard to reduce customer electricity consumption through greater energy efficiency. Customers expect PGE to promote energy efficiency because it is the right thing to do and it is cost effective; energy efficiency helps customers reduce their monthly bills and it helps conserve natural resources used in making electricity. However, the tradeoff is that without load growth in our service territory, it is difficult to have sufficient revenues to offset inflationary and other cost increases.

Our filing also includes earning a fair return on our investment to attract capital at a reasonable cost. Failure to raise customer prices as requested in this case, would significantly impact our ability to raise capital and the future cost of capital, which ultimately would increase the cost of capital for investments needed to serve customers and thus increase customer prices.

Q. What increase in prices does PGE request in this proceeding?

A. PGE requests that prices be adjusted on January 1, 2014, to yield $104.8 million of additional revenues (a 6.2% increase overall) on an annualized basis. The total includes approximately $2.3 million of Boardman decommissioning costs, and $26.8 million associated with capital projects, subject to a deferral authorized in UE 215 which would likely be recoverable absent this filing. The net impact without the capital projects is $78.0 million or 4.8%. We recognize that certain key estimates will be adjusted throughout 2013, and that other proceedings before the Commission may also result in changes to this filing. Please see PGE Exhibit 300 for more detail on our request.

The $104.8 million revenue requirement increase is tied directly to meeting our customer expectations for service and system reliability of our generation, transmission, and distribution assets, and responding to new regulatory requirements and other external cost drivers such as pension plan funding and health insurance.

Q. Please put the requested price increase in context relative to PGE's prices since the last general rate case.

A. Since our cost of service prices have declined in each of the last two years, our requested increase is roughly 3.5% over those prices approved in UE 215, and this includes the impact of the capital projects discussed above.

Q. What are the consequences if PGE were not to file this rate case?

A. Not filing this rate case would significantly compromise our ability to continue to meet customer expectations for safe, reliable, adequate electricity and our regulatory obligations. Without this filing, our actual ROE is expected to be about 5.9% compared with the currently authorized level of 10.0%. This would markedly affect our ability to compete for capital at a reasonable cost. This case lays the foundation for the future of PGE as a utility that: 1) performs exceptionally in providing reliability and meeting customer needs in an environment where customers make choices, compare PGE with other businesses, and compete in markets with global standards; and, 2) is a good corporate citizen, fulfilling its mandated regulatory requirements.

Q. Have you taken into account the impact of your request on customers' bills, given the state of the economy?

A. Yes. We understand Oregon has been slow to recover from the recession and the recession has been hard on our residential, commercial and industrial customers. For that reason, we led the charge to enact increased energy assistance funding (Senate Bill 863) to help our most vulnerable customers. We have also stepped up our efforts to help connect our customers with programs at the Energy Trust of Oregon designed to help them become more energy efficient and reduce energy consumption. We also have worked hard to manage cost increases and our request in this case. In fact, as I noted earlier, customer prices are down since our last general rate case. PGE Exhibit 200 goes into further detail on our efficiency and cost management efforts to affect customer price increases.

Despite our enterprise-wide efforts to control costs these past three years, PGE now needs to request an increase in customer prices. We have made adjustments in our filing because we recognize the impact of a price increase on our customers. Prior to filing this rate case, we scrutinized budgets, prioritized the drivers and identified specific reductions we could make to mitigate the customer impact of the request. To further mitigate customer impacts and even though we have support for a higher Return on Equity (ROE) request, this filing reflects a request for 10% ROE, that is at the bottom of the range of estimated equity costs provided by our expert witness, Thomas Zepp in PGE Exhibit 1200. PGE Exhibit 300 discusses additional reductions we have made to our request totaling $29.5 million.

II. Customer Expectations

Q. You mentioned meeting customer expectations. How do you know what customers expect?

A. We regularly conduct customer satisfaction studies of our residential, general business, and key customers to learn what our customers care about and we receive feedback about gaps in PGE's performance. We gather feedback in many other ways as discussed in PGE Exhibit 900, so we are constantly getting insights from our customers about how to improve and better meet their needs. I take this feedback very seriously; it is incorporated in how we manage our business now and in the future.

Q. How does PGE incorporate customer expectations into its operations?

A. PGE incorporates customer feedback and expectations into our operations starting at the highest level with what we call strategic direction. PGE's strategic direction identifies three core business strategies: operational excellence, business growth, and corporate responsibility.

Q. How does the business strategy, Operational Excellence, relate to PGE meeting customer expectations?

A. Customers expect that we keep our service quality high by regional and national standards while maintaining affordable, reasonable prices. We meet these expectations through operational excellence – working hard to maintain strong customer service and high levels of availability and reliability of our transmission and distribution system, and generating plants. We are pleased to be recognized among the top quartile of investor-owned utilities for residential, general business and large industrial customer satisfaction. In the 2012 annual TQS[1] survey, large industrial customers ranked PGE number one nationally for reliability. Our operational excellence results are actually fundamental to our second core business strategy: business growth.

Q. How does the business strategy of business growth relate to PGE meeting customer expectations?

A. Businesses have choices in terms of whether to locate within our service territory and whether to purchase energy from PGE or an energy service supplier. Over the years, key business customers have moved into or expanded in our service territory, at least partially, because of the level of reliable service we provide. We have been told that our high reliability is an important factor for several high tech customers locating in our service territory and attractive to data centers choosing to locate in our service territory. We need to maintain our record of high-quality, reliable service to retain and grow existing businesses, and attract new businesses with the jobs they create for our residential customers. The economic growth that results will enable us to offset operational cost increases through the accompanying load growth. Our business success is linked with that of our customers.

Q. How does the business strategy of corporate responsibility relate to PGE meeting customer expectations?

A. Corporate responsibility means being a good corporate citizen and includes community involvement. Our customers expect us to be involved in their communities and to provide service that reflects their values. Last year alone, PGE employees and retirees volunteered over 47,000 hours of their own personal time to community organizations, and they donated over $1.1 million to more than 1,000 schools and nonprofits. Their commitment to meeting

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[1] The TQS survey is conducted by TQS Research, Inc.

community needs has become one of the most impressive and inspiring elements of the PGE culture.

Q. What else is involved in corporate responsibility?

A. Corporate responsibility also means conducting our business with integrity and diligently complying with increasingly complex and costly rules and regulations from a variety of state and federal agencies, including the Federal Energy Regulatory Commission (FERC), Western Energy Coordinating Council (WECC), North American Electric Reliability Corporation (NERC), Securities Exchange Commission (SEC), Department of Environmental Quality (DEQ), Department of Energy (DOE), Environmental Protection Agency (EPA), Nuclear Regulatory Commission (NRC), and the Oregon Occupational Safety and Health Division (Oregon OSHA).

Q. How does the strategic direction then get implemented?

A. Our strategic direction is implemented through scorecards at every level of the company. Each officer has responsibility for elements of the strategic direction in his or her scorecard, which sets the objectives and outcomes expected for the officer's organization for that year. The officer's scorecard outcomes are then broken down into increasingly granular objectives throughout their organization. The performance of every employee at PGE, including me, is measured against these objectives and directly influences compensation decisions (see PGE Exhibit 500). Using this scorecard system helps us constantly improve, driving us to incorporate performance metrics and aim to improve year over year.

III. Benchmarking and Improvement

Q. In addition to the scorecard system, what else drives PGE's improvement process?

A. The improvement process is also driven by benchmarking and best practices exercises, where our work teams analyze things we do well, identify gaps in our performance relative to peers, and propose cost effective improvement initiatives to reduce costs or improve performance. Every major area of the company has completed a benchmarking study. I am personally challenging the organization to make benchmarking an ongoing part of our business culture as the foundation of improvement plans. The learning from the benchmarking process leads to continuously becoming more efficient and effective as an organization.

Q. Do customers care about this effort to improve efficiency and effectiveness in operations?

A. Not only do customers care about it, they expect it. Customers expect that their energy needs are met both efficiently and effectively, resulting in better service for lower cost. In a constantly changing environment, we have to continuously review what we do, how we do it and how we can improve, or we will lose the confidence of our customers.

Q. How do you measure improvement in efficiency and effectiveness?

A. We start where we are. We benchmark, review the findings, make changes, and then benchmark again, reviewing and implementing improvements. The changes we make are based upon what makes business sense for our customers, considering costs and benefits, technology changes and timing. In our last general rate case, UE 215, we provided high level benchmarking analyses by consultant Pacific Economics Group (PEG) that indicated we were generally within the range of performance with other utilities on areas benchmarked.

However, to improve, we needed to go deeper than the PEG study. We have embarked on a process to incorporate detailed benchmarking efforts throughout our organization. To date, we have benchmarked and identified best practices for most areas of the company. PGE Exhibit 203 provides a preliminary forward-looking benchmarking schedule. While we are on a path of continuous improvement and efficiency, it is by definition a process that takes time and is never "finished." It has to occur at a pace that the organization can accomplish, taking into account changing standards, technologies, and expectations while simultaneously delivering safe, reliable, adequate, and reasonably-priced electric power to our customers using the resources available to us today.

An overview of our efficiency and continuous improvement activities is further discussed in PGE Exhibit 200 provided by Maria Pope, Senior Vice President of Finance, Chief Financial Officer and Treasurer and Tamara Neitzke, Director of Planning and Performance Management.

Q. What have you learned from benchmarking efforts?

A. We have learned that PGE is generally effective in what we do; in some areas we are highly efficient; in others, less so. This was not a surprise to us and surely is not a surprise to our stakeholders. Even before comprehensive benchmarking, in particular, we had identified a number of information systems that were not up-to-date and had begun implementing a program to systematically evaluate and update our major technology systems by the year 2020. In UE 215, we discussed the need to replace our 26-year-old financial and supply chain system – an effort that was completed in 2011 and has yielded some significant benefits. For example, using the new system, PGE's procurement staffs are now able to better leverage our buying power to negotiate more favorable terms with vendors. We now conduct spending analyses that were not possible with the old system.

As part of our plan, following the financial and supply chain system replacement, we began the process of replacing our work-management systems. We made that decision based on the efficiencies we could gain by moving from approximately seven work-management systems to one new system, known as Maximo. Our next step, and an integral part of this rate case filing, involves conducting the precursor work necessary to transform the ways we serve our customers, a project we call Customer Engagement Transformation (CET). It is a multi-year initiative that examines and redesigns customer service business strategies, business processes and employee skills, in preparation for replacing outdated technology systems including the customer information system. In PGE Exhibit 900 we discuss this initiative in detail and explain the necessity of the work being done in 2013 and 2014 to lay the foundation for additional work in 2015 through 2018.

The benchmarking work we did in regard to employee safety delivered a powerful insight. We believed PGE to have been performing well on employee safety indicators compared with other utilities. As a result, we did not focus enough attention on improvement. When we benchmarked and identified best practices, we learned that other companies had made significant improvements in employee safety, and found ourselves bottom quartile on some indicators. This is unacceptable to me. We must and we will improve employee safety at PGE. To realize this goal we are developing a worker-safety culture and improving safety practices. Our employees perform dangerous work, but no job is so important that we cannot take the time to do it safely. The culture change focuses on having employees keep safety ever-present in their minds as they work, and if they identify safety risks or hazards, to speak up — no matter what the situation is or their position. It is critical to ensuring that new work practices are implemented consistently across our organization. Our employee safety initiatives are discussed in more detail in PGE Exhibit 800.

Q. Now that you have completed benchmarking for most areas of the company, are you finished?

A. No. As we learned with employee safety, if we are not continually assessing and improving, we will fall behind. Benchmarking cycles are becoming a part of our company culture: we benchmark and identify best practices, we review results, we learn and change; we benchmark again. My goal is to inspire continuous learning among managers and employees so it becomes part of our culture— to identify best practices, both in the electric utility industry and other industries, incorporate appropriate business-case-driven changes and continue to improve over the long term.

Q. Now that you have these benchmark results, should they be used to set performance targets for PGE?

A. No. Fixed performance targets are not appropriate because while benchmarking offers significant value, it is also inexact. It cannot take into account all of the differences between companies such as the vintage of technology systems, the size and diversity of the generation fleet, the statutory and regulatory environment, the economic environment, customer expectations and values, and the list goes on. Benchmarking offers information on where to look for efficiency but does not provide a strategy for the most effective way to achieve it.

Q. If setting performance targets based on the benchmarking results is not appropriate, why are you sharing the results?

A. We discuss our benchmarking studies in an effort to be transparent about what we are doing and to highlight our commitment to continue to improve. In discussing our findings, we know we run the risk that some may be tempted to propose externally-driven targets for PGE to achieve over a given time. My hope in sharing these results is to communicate that driving improvement and efficiency is one of my top priorities. I intend to hold my management team accountable for progress and results on our improvement plans. We will routinely keep the Commission informed of our progress.

Q. What is involved in managing the improvement activities arising from the benchmarking?

A. Managing benchmarking and the resulting change processes also means keeping in mind our ongoing responsibility to provide adequate, safe, reasonably-priced service. We cannot put this responsibility on the back burner in order to implement changes. In managing these processes, we have to stay abreast of the rate and amount of change; I am concerned that taking on too much change or forcing a high rate of change could overwhelm the organization as the capacity and resources to manage change reaches its limits. We are thoughtful and deliberate about how we implement and sequence improvement initiatives. Some initiatives take time and may involve longer-run technology changes, changing processes or employee skill sets that take time to cultivate.

Q. How are you managing the pace of change resulting from benchmarking?

A. Some employees say that we are changing too fast. Others, I am sure, say that we are not going fast enough. Setting the right level of change and shifting cultural aspects are a key management focus. We must not implement change so fast that it compromises our safety, reliability or service to customers and not too slow that efficiencies are not achieved in a timely manner.

Q. You mentioned the benchmarking/improvement cycle as a means to become more efficient. Are there other factors in PGE's operating environment that are raising costs despite your efforts to manage costs and improve efficiency?

A. Yes. The operating environment has become increasingly complex and regulated. This is simply a reality in managing our business and is driven by legitimate public goals, concerns and aspirations. Because of the importance of electric service to our customers, there is great interest in ensuring we meet their reliability requirements. There are many federal and state agencies and advocacy groups with responsibilities or interests that affect our business, which has resulted in increased regulation. While we work to reduce costs and become more efficient and effective, at the same time, new costs of compliance are being added. These are important changes that are part of the nature of our industry and we are expected to comply.

Q. Please provide examples of the increased regulatory requirements you are seeing.

A. In the last several years, we have seen increases in FERC, WECC and NERC regulations relating to security of the grid; federal EPA and Oregon DEQ regulations on air quality and greenhouse gas reduction, and new laws governing financial transactions and accounting controls such as Dodd Frank.

To keep abreast of and comply with new regulations, PGE must increase staffing and training. For further discussion, see PGE Exhibits 800, Transmission and Distribution, and 600, Information Technology.

IV. Perspective on this Filing

Q. Given the context, what are you trying to achieve in this filing?

A. Rate cases are frequently filed to meet the needs of our customers, and this one is as well. Part of this case addresses legacy issues and fulfilling commitments or meeting requirements; others lay the ground work for meeting customers' future needs.

Q. How does this rate case filing deal with legacy issues or meet requirements?

A. One example of how our filing fulfills commitments is PGE's request for recovery of $3.2 million of emission control chemicals at the Boardman coal-fired plant including Dry Sorbent Injection (DSI). DSI fulfills a federal Clean Air Act requirement to reduce emissions of sulfur dioxide, meeting EPA and DEQ standards for mercury and air toxics, as well as regional haze. Reflecting least-cost planning decision principles in our 2009 Integrated Resource Plan,[2] this is part of PGE's aggressive, cost-efficient action plan to dramatically cut haze-causing emissions from the plant as our part of our commitment to improve visibility in wilderness areas and national parks such as Mt. Hood and Mt. Rainier. In addition to the planned DSI controls, we have already installed required controls to substantially cut the plant's emissions of airborne mercury and oxides of nitrogen.[3]

Another example of fulfilling commitments is ensuring that our employees and retirees receive the appropriate pension included as part of a balanced compensation and retirement plan. Providing competitive compensation and retirement benefits is key to attracting and retaining a high-quality, experienced workforce, which is critical to meeting our customers' service expectations. Although PGE's pension fund is well-managed and has outperformed

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[2] The 2009 PGE IRP was acknowledged by the Commission in 2010.

[3] The Oregon Environmental Quality Commission (OEQC) adopted final rules pertaining to mercury emissions from Boardman, requiring compliance by mid-2012, PGE installed controls in 2011 that are expected to eliminate 90% of the mercury emissions from the plant to comply with the rules.

similar funds across many industries, long-term investments have returned less than anticipated due to the economic downturn; actuarial assumptions have changed; and interest rates have declined dramatically. Those are all wider market trends beyond PGE's control. At the same time, mandatory pension funding standards under the federal Pension Protection Act have dramatically increased the need for employer contributions – affecting many employers, including PGE. As a result of these changes, our pension – which we closed to new employees in 2009 – has gone from being fully funded to requiring significant cash infusions, and PGE has contributed more cash to the pension plan than has been included in our customer prices. We are asking that the additional cash contributions to the pension plan be treated as a prepaid asset and that the Commission recognize the long-term financing cost associated with these cash outlays. We expect to contribute more than $180 million in the next ten years to meet this commitment. More information on PGE's pension liability and request is in PGE Exhibit 500.

A third example in this category of meeting requirements is PGE's plan and its associated costs, to comply with the NERC Critical Infrastructure Protection, version 5 standards and requirements. The standards provide a cyber-security framework to identify and protect all cyber assets that could cause a disturbance to the Bulk Electric System. To comply, PGE must address training, tracking users' access, managing assets and vulnerabilities, and monitoring compliance. Fines for violations can be as much as one million dollars per violation per day. The requirements' far reaching details and our compliance plan are addressed in PGE Exhibit 600.

Q. Why is this rate case necessary to meet customers' needs?

A. Let me give some examples:

- As we discussed in our last general rate case and in the benchmarking discussion, we have identified several legacy technology systems that have served customers well for many years, but need to be replaced to meet ongoing, evolving customer needs and to allow us to become more efficient in our operations. In this rate case, PGE is including $8.0 million in costs to prepare for the replacement of our customer information system and transform our customer engagement by taking significant steps to identify and implement best practices. This is further discussed in PGE Exhibit 900.
- As directed by the Commission, PGE is planning for unpredictable acts of nature, including seismic events and other emergencies. Our plan includes construction of a "Readiness Center," discussed at greater length in PGE Exhibit 600, located and constructed to withstand up to a 9.0 earthquake from the Cascadia Subduction zone. The Readiness Center, which will become operational by the end of 2013, will house and back up key data and technology systems, and will serve as PGE's Emergency Command Center.
- We took advantage of TriMet's expansion of light rail into some of our Portland Service Center property, by purchasing the Avery site in Wilsonville. The new facility at Avery will be the home for consolidated dispatch that was formerly dispersed among our southern, eastern, and western region line crew centers. We have also consolidated other work groups, actually reducing our facilities' footprint while maintaining the response capability of our line employees. By creating a single, company-wide dispatch group, we are able to better share work and resources across regions, reducing how often jobs get rescheduled and reduce our contract

rental equipment and excavating costs. It will also give dispatchers a company-wide look at all the work across all regions and lead to more efficient and effective scheduling and dispatching, ultimately benefitting customers.

- We are transforming our transmission and distribution areas by adding capability for automatic vehicle location, mobile scheduling and implementing just one work management system, Maximo.

V. Policy Issues

Q. Do you propose the continuation of PGE's decoupling adjustment?

A. Yes. Decoupling was originally instituted on a pilot basis for two years and then extended another three years through 2013 in our last general rate case. We support its continuation. Decoupling removes the disincentive for us to encourage energy efficiency measures to our customers. Energy efficiency remains a key component of our resource planning efforts and a key priority of the governor in his ten-year energy plan. We believe it makes sense to maintain this mechanism in support of those efforts.

Q. Do you recommend any changes to your decoupling mechanism?

A. No.

Q. Does PGE's decoupling mechanism warrant a reduction in PGE's ROE?

A. No. As noted in more detailed testimony from our expert, Thomas Zepp in PGE Exhibit 1200, a recent study questions the conclusion that decoupling reduces a utility's risk profile. Dr. Zepp notes that the discounted cash flow cost of equity estimates takes decoupling benefits into account as sixteen of the twenty utilities in the benchmark cost of equity sample have decoupling of some kind in at least one state in which they do business.

Q. Is PGE proposing any other policy changes?

A. Yes. We are asking for accounting orders to moderate cost volatility of the following:

- Storms – We are requesting continuation of the storm deferral accrual granted in UE 215, with a modification. Currently, PGE is allowed to collect in rates approximately $2 million each year that accrues in a storm damage restoration account that can be used to help offset future major storm damage. PGE requests that the account be modified to be a balancing account, such that major storm damage costs in excess of what has been collected so far be included in the balancing account and offset over time by future accruals. Please see PGE Exhibit 300 for further discussion.

- Pension – PGE has included a balancing account for pension-related costs, including pension expense and a return on the prepaid pension asset. Inclusion of this balancing account has reduced PGE's request in this case by approximately $14 million. PGE Exhibit 500 discusses the balancing account in more detail.
- Maintenance accrual – PGE proposes a major maintenance accrual for Port Westward similar to the one in place for Coyote Springs. Such an accrual smooths cost and recovery for customers and ensures they only pay for costs incurred. PGE Exhibits 300 and 700 discuss this in more detail.

VI. Conclusion

Q. Will approval of PGE's request serve the interests of customers?

A. Yes. Customers benefit from our investments in people, processes and systems geared to maintain and improve the services they receive from us based on the changing technologies, business environment, and regulatory requirements that arise.

Q. Will the results of this rate request affect PGE's access to and cost of capital to fund investments in the near future?

A. Yes. PGE is assuming for the purpose of its initial filing that we will have significant capital requirements over the next several years related not only to generating and transmission facilities but also to ongoing investments in our system and improvements such as those addressed by 2020 Vision. The 2020 Vision Program is a long-term company initiative to consolidate and modernize PGE's technology infrastructure and work processes. The program's purpose is to ensure that PGE can meet the changing needs of both the company and our customers. It is further discussed in PGE Exhibit 600.

Our access to capital and the cost of that capital is influenced by our having the opportunity to earn our authorized return on equity. As mentioned above, without this rate case, PGE's projected return on equity is 5.9%, well below the 10% authorized by the Commission. If that were to occur, our bond ratings could be negatively impacted as well. In short, the outcome in this rate case will have an impact on our access to capital and its cost to fund near term and future investments. For more information on how the investment community views regulation and its impact on access to capital see PGE Exhibit 1100.

Q. Why should the need for future capital be important to this rate case when the capital investments requiring funding are not part of the 2014 test year?

A. A foundational purpose of investor owned utilities is to access capital markets for the public good. The utility industry as a whole expects to make significant capital investments over the next several years, and PGE must be positioned to compete for capital while maintaining financial stability and its investment grade credit ratings. According to an Edison Electric Institute study, investor-owned utilities are projecting $79 billion to $94 billion annually in capital spending 2012-2014.[4] The choice to loan or invest in PGE will be viewed alongside many other investment opportunities in competing utilities and other industries. Though the costs of the investments themselves are not included in the test year, PGE does anticipate spending up to approximately $940 million in 2014, more than three times what PGE spent in 2011.

Q. How is PGE presenting this case?

A. PGE is presenting the following direct testimony:

- In Exhibit 200, Maria Pope, Senior Vice President of Finance, Chief Financial Officer and Treasurer, and Tamara Neitzke, Director of Corporate Planning and Performance Management describe PGE's continuous improvement efforts and commitment to efficiency. Improvement efforts undertaken throughout the company are highlighted in each area's testimony as well as the overview in Exhibit 200.
- In Exhibit 300, Alex Tooman and Chris Liddle, Regulatory Affairs Project Managers, summarize PGE's requested bundled and unbundled revenue requirement for the 2014 test year.
- In Exhibit 400 Mike Niman, Manager, Financial Analysis and Terri Peschka, General Manager, Power Operations support PGE's initial estimate of Net Variable

[4] http://www.eei.org/whatwedo/dataanalysis/indusfinananalysis/pages/qtrlyfinancialupdates.aspx.

Power Costs (NVPC) for the 2014 test year and presents certain changes to the Monet model to forecast costs.

- In Exhibit 500, Arleen Barnett, Vice President of Administration and Joyce Bell, Director of Compensation and Benefits describe PGE's compensation philosophy and presents the projected 2014 test year costs for wages/salaries, benefits, and incentive compensation. Jardon Jaramillo, Senior Investment Analyst in the Finance Department describes current circumstances PGE is facing with regard to pension costs, its pension investment strategy, and a plan to reduce customer price volatility from pension costs.
- In Exhibit 600, Cam Henderson, Vice President of Information Technology (IT) and Chief Information Officer, and Behzad Hosseini, Director of IT Strategy and 2020 Vision, describe the current IT environment, provides an update on the 2020 Vision project, and details the drivers of cost changes in IT, including cost efficiencies and controls. Among the cost drivers, the testimony also describes PGE's plan and costs to comply with the Critical Infrastructure Protection standards issued by the NERC.
- In Exhibit 700, Stephen Quennoz, Vice President, Power Supply, and David Weitzel, Regulatory Affairs Project Manager summarize PGE's resource base and describes the fixed Operations and Maintenance (O&M) and capital costs associated with PGE's plant and power operations areas. In addition, the testimony provides information on our excellent plant performance, the changing environment, efforts to reduce emissions, and efficiency successes.
- In Exhibit 800, Bill Nicholson, Senior Vice President of Customer Service, Transmission and Distribution, and Bruce Carpenter, Vice President of Distribution

support PGE's efforts in the delivery function, explaining PGE's test year forecast of Transmission and Distribution (T&D) O&M non-labor costs and capital expenditures. The testimony includes detail on PGE's T&D transformation project undertaken to improve customer service, reliability and efficiency.

- In Exhibit 900, Kristin Stathis, Vice President of Customer Service Operations, and Carol Dillin, Vice President of Customer Strategies and Business Development, support PGE's customer service activities for the 2014 test year, including O&M non-labor costs and PGE's estimated uncollectible rate for the 2014 test year. In addition, Exhibit 900 discusses in detail the Customer Engagement Transformation program, a multi-year improvement initiative and cost driver in this rate case.
- In Exhibit 1000, Maria Pope, Senior Vice President, Finance, Chief Financial Officer, and Treasurer and Alex Tooman, Regulatory Affairs Project Manager, describe cost increases in PGE's corporate support functions, or Administrative and General. The testimony also provides detail on the cost drivers, benefits and regulatory compliance, as well as cost reduction and efficiency measures implemented.
- In Exhibit 1100, Patrick Hager, Manager of Regulatory Affairs and William Valach, Director of Investor Relations for PGE provide support PGE's forecasted cost of capital for 2014. It discusses PGE's cost of long-term debt and risk, and supports PGE's proposed capital structure.
- In Exhibit 1200, Thomas Zepp, Economist, addresses PGE's equity costs, applying the Discounted Cash Flow and Risk Premium models that indicate a reasonable range of ROEs from 10.0 to 10.7%. Noting that PGE is riskier than the benchmark

sample used, the expert and testimony author, Thomas Zepp, supports PGE's requested 10.0% ROE, while at the low end of the range, as reasonable.

- In Exhibit 1300, Ham Nguyen and Sarah Dammen, PGE Economists, provide testimony on PGE's load forecast. PGE forecasts that 2014 total deliveries to customers will be 19,233 million kilowatt-hours (kWh).
- In Exhibit 1400, Bonnie Gariety, Rob Macfarlane, and Bruce Werner, Pricing and Tariffs Analysts, present PGE's Marginal Cost Study, including generation, customer service, and distribution costs. The study is then used as a basis for rate spread, rate design and proposed prices, detailed in PGE Exhibit 1500.
- In Exhibit 1500, Marc Cody and Rob Macfarlane, Senior Pricing and Tariffs Analysts present PGE's proposed prices to recover the revenue requirement, revenue requirement allocation process, and rate design. The testimony also discusses changes to the residential basic charge, and Schedules 83 (creating mandatory time of use rates), 85 (consolidating with smaller Schedule 89 customers), 89 (defining customer class as customers over 4,000 kW), 123 (continuing decoupling) 125 (Annual Power Cost Update), and Schedule 145, (Boardman Power Plant Operating Life Adjustment to recover revenue requirements associated with decommissioning by 2020), and Outdoor Lighting schedules to reflect marginal, rather than embedded, cost of luminaires and poles.

VII. Qualifications

Q. Mr. Piro, please describe your educational background and experience.

A. I received a Bachelor of Science degree from Oregon State University in Civil Engineering in 1974 with an emphasis in Structural Engineering. In addition, I have taken postgraduate courses in engineering, accounting, economics, and rate making. I am a registered Professional Engineer in Civil Engineering in the State of California (Registration No. 28174). I joined Portland General Electric in 1980 and have held various positions in Generation Engineering, Economic Regulation, Financial Analysis and Forecasting, Power Contracts, Economic Analysis, Planning Support, Analysis and Forecasting, and Business Development. I was elected Vice President of Business Development in 1998 and then became Chief Financial Officer and Treasurer on November 1, 2000. I was then named Senior Vice President, Finance, Chief Financial Officer and Treasurer on May 1, 2001, and then became Executive Vice President, Finance, Chief Financial Officer and Treasurer effective July 25, 2002. I entered my current position as President and Chief Executive Officer effective January 1, 2009.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 262

Corporate Performance
&
Efficiency

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Maria Pope
Tamara Neitzke

February 15, 2013

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I. Introduction

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

A. My name is Maria Pope. I am Senior Vice President, Finance, Chief Financial Officer and Treasurer for PGE.

My name is Tamara Neitzke. I am Director of Corporate Planning and Performance Management at PGE. Our qualifications are included at the end of this testimony.

Q. What is the purpose of your testimony?

A. PGE is committed to maintaining its focus on providing customers with safe, reliable, adequate, and reasonably-priced electricity while also meeting customers' broader service expectations, laying the groundwork for future needs, and achieving all required regulatory standards. The purpose of our testimony is to describe how PGE's improvement efforts and commitment to efficiency are an integral part of this effort. By working to mitigate rising costs while maintaining effectiveness, we are able to keep our revenue requirement request in this proceeding – and thus our prices – much lower. Through our improvement efforts, we project O&M savings and avoided costs of $15.6 million in 2014. As we continue to emphasize cost efficiency in our operations, we expect to see savings accrue for our capital projects as well. PGE Exhibit 201 provides a summary of O&M efficiency savings.

Q. Please explain what you mean by efficiency and effectiveness?

A. Efficiency is aimed at how we deliver reliable energy and service to customers while maintaining standards for safety and regulatory compliance. Technically, efficiency is measured by comparing the ratios of output to input. A system increases its cost efficiency when it maintains output with fewer or less costly input(s), or conversely delivers higher value to customers for the same or lower cost. Effectiveness is the quality measure of output.

Our efficiency and effectiveness efforts aim to contain or reduce costs while keeping our high quality of customer service and system reliability. We are not effective if our system is not safe, not reliable, or we are not providing good customer service. This differs from mere cost cutting; obtaining the lowest absolute cost is not a responsible goal if it sacrifices our effectiveness in delivering safe, reliable power.

Q. Why are efficiency and effectiveness important?

A. Our customers depend on PGE to run an efficient operation, while meeting their growing needs, by keeping our costs down while maintaining effectiveness by providing safe and reliable power.

Q. What factors are considered in defining PGE's appropriate range of efficiency and effectiveness?

A. We use industry peer group analyses to help define appropriate ranges of effectiveness and efficiency for business areas. However, industry analyses often consider the efficiency and effectiveness metrics on separate scales and it is important to define an appropriate combination of these two metrics. The appropriate balance varies across industries, businesses and functional areas due to varying requirements and characteristics including compliance and reliability obligations. When striving for the appropriate combination, we must also manage the improvement changes we make in a way that the organization can absorb and integrate those changes effectively. PGE, as most businesses, has a maximum threshold for change absorption that must be considered when reviewing and prioritizing improvement initiatives. Change absorption represents how much change PGE can effectively undertake at any one time.

Q. How is operational efficiency and effectiveness incorporated into PGE?

A. Operational excellence is an integral part of PGE's strategy. Its objectives are to demonstrate operational cost effectiveness while upholding our commitment to performance, safety and customer satisfaction. Operational efficiency and effectiveness is a shared expectation throughout the organization. The Corporate Performance Management group (Corporate Performance) leads our efforts towards improvement while the expectation to drive for efficiency lies within all business units. This structure provides centralized leadership of the decentralized efforts to achieve continuous improvement and operational efficiency.

Q. How is PGE moving forward with its improvement efforts?

A. In our last general rate case, UE 215, we hired Pacific Economics Group (PEG) to perform a high level econometric analysis benchmarking PGE's operations. The study illustrated PGE's overall effectiveness while maintaining O&M expenses that were in line with industry standards. The study provided a useful starting point with a high-level analysis of PGE operations, but since then we have probed deeper with comprehensive functional benchmarking efforts targeting all business areas of PGE. Please see Section II for an explanation of PGE's improvement cycle and efforts since UE 215.

II. The Continuous Improvement Cycle

Q. What is a continuous improvement cycle?

A. A continuous improvement cycle involves the constant effort toward improvement. The cycle does not end when we reach the last step, but rather repeats.

Q. Please describe PGE's continuous improvement cycle.

A. At a very high level, our improvement cycle includes the following:

1) Benchmarking. The process begins by benchmarking key areas of PGE's business that drive performance. Benchmarking compares the effectiveness and efficiency of PGE's operations against peers within and outside the utility industry, where appropriate. Metrics are reviewed by a third-party for validity to ensure the best "apples-to-apples" comparison. Benchmarking is not the final answer but rather the beginning step towards improvement. The true value is realized with the improvement work that follows.

2) Synthesizing Results. After benchmarking, data are reviewed from top-performing companies to identify best practices. The combination of benchmarking results and best practices are then synthesized to identify areas of strength and improvement opportunities. Best practices provide us insight as to where change might be possible to improve our performance and ultimately our benchmarking results in the future.

3) Strategizing. The improvement opportunities are then prioritized. Improvement projects that require internal funding are required to supply a business case illustrating the proposed change. A business case must describe the scope, justification and cost of the project. When applicable, projects are then reviewed by the appropriate committee to assess each project's capability and possible approval. (Note: not all improvement projects require internal funding and thus don't require a business case.) Lastly,

improvement efforts are targeted to work in line with the overall business strategy of delivering safe and reliable power to customers.

4) Initiative Development. After the strategy is defined, a roadmap of initiatives is developed to help guide projects to completion. Initiatives such as system automation and Lean process reviews have had a substantial impact. As projected savings associated with initiatives are quantified, we remove those savings from operational budgets, thus, creating a cycle of accountability among management to accomplish defined initiatives.

5) Cycle Repeats. The benchmarking cycle is repeated: (1) once initiatives are in place and a business unit has completed its strategy, or (2) it is an appropriate time to measure improvement progress. As each functional group is in a different stage of reviewing its organization for improvement opportunities, benchmarking cycles vary.

Q. How does PGE determine which business units to benchmark?

A. The goal of the corporate benchmarking initiative is to review all major business functions within PGE. However, identifying the business units to be benchmarked is largely determined by the availability of peer data and existing benchmarking opportunities. Common utility functions such as Information Technology and Customer Service have well established vendors with reliable data that offer benchmarking programs. Less common functions or very specialized areas such as Corporate Communications and Governmental Affairs are more difficult to benchmark as less data are available and the functions included vary greatly.

Q. How are peer groups selected?

A. Peer groups are most commonly selected by the benchmarking vendor and result from two different approaches to benchmarking: (1) If the benchmark is a recurring annual study, the peer group is composed of organizations that chose to participate in that particular study; and (2) If a vendor has a well-established database of cross-sectional company data, there is more flexibility in selecting an appropriate peer group. Common factors used to create peer groups from a database include: industry type, number of employees, revenue, and customer base.

Q. Has PGE benchmarked most areas?

A. Yes. PGE Exhibit 202 provides a list of benchmarked areas, the vendor, and timing.

Q. Which areas have not finished their first continuous improvement cycle?

A. Customer Service, Shared Services, and Legal have been benchmarked and are in the process of reporting and synthesizing the results from the benchmark studies. Throughout 2013, each area will analyze results, review best practices and begin to develop an overall strategy and roadmap for improvement. Public Policy is currently analyzing work processes and developing an internal review based on best practices in the industry. A preliminary benchmarking schedule is listed in PGE Exhibit 203.

Q. What major improvement initiatives have been completed, are underway, or are being developed?

A. PGE has numerous improvement initiatives completed or underway as a result of our benchmarking activities, process improvements, or other activities. Some of these major initiatives are:

- <u>Transmission & Distribution (T&D) Transformation</u> is an effort to improve work processes and leverage technology to improve safety, accountability, standardization, productivity, and efficiency in transmission and distribution. The transformation program projects O&M annual savings of $3.4 million in 2014. Details can be found in PGE Exhibit 800, Section II.

- Financial Systems Replacement Project (FSRP) replaced PGE's obsolete 26-year old Masterpiece system with a new financial system that enables streamlined workflow and automation of many manual processes. Examples of streamlined workflow include:
    - 40% reduction in cash management processing time; and,
    - Automation of 80% of book-tax adjustments.

  FSRP, in conjunction with Lean process analysis, allowed for Finance and Accounting (F&A) to realize efficiencies through a net reduction of approximately 11 Full Time Equivalents (FTE) through 2012 and another 4.3 FTEs by 2014. Details can be found in PGE Exhibit 1000, Section II, Part A.

- Procurement Efficiencies via Strategic Sourcing consists of performing spend analysis by utilizing our new financial system (FSRP), identifying business requirements, understanding the marketplace, developing a supply category strategy, evaluating and selecting suppliers, negotiating agreements, developing scorecards to measure supplier performance and then repeating the process to drive continuous improvement. In 2012, PGE negotiated over $7.6 million of O&M cost savings and $2.6 million of O&M avoided costs[1] that span multiple years (i.e., $1.4 million in 2012, $1.2 million in 2013, $1.1 million in 2014, and the remaining $6.5 million after 2014). Details can be found in PGE Exhibit 1000, Section II, Part A.

- Lean Processing in Human Resources – Lean processing is a process improvement methodology that focuses on removing "waste" from processes so that efficiencies in

[1] Based upon Utility Purchasing Management Group (UPMG) definition of cost savings and cost avoidance. See PGE Exhibit 1006 for definitions.

time and resources can be achieved. Waste can be anything from wait time, to errors and re-work, to extra processing. As processes are improved, productive resources can be reallocated to higher-value activities. PGE's Human Resources (HR) has completed 20 Lean processes with more in progress. Details on HR Lean processing efforts can be found in PGE Exhibit 1000, Section II, Part C.

- Employee Benefit Provision Mitigation – Health care reform will have a significant impact on medical plan design and cost as it evolves over the next few years. PGE is monitoring health care reform, and we are evaluating possible future changes to existing benefit plans. In preparation for reform, we have modified many benefit provisions to offset the full effect of increases in benefit costs while maintaining an effective level of benefit support for employees. Some of the benefit changes are:
  - Increasing deductibles and co-pays;
  - Adding additional coinsurance to various plans; and,
  - Offering high deductible plans by each vendor in addition, not in lieu of other offerings.

  PGE evaluates if a change in benefit options offered is prudent and if further cost shifting to employees, in terms of out-of-pocket contributions, deductibles and choices of care are appropriate. See PGE Exhibit 500, Section IV for more details on how PGE is working to mitigate benefit cost increases.
- myTime is a web based time collection system (TCS) that will increase accuracy and reduce resources spent on time-keeping processes and payroll. myTime will replace the currently obsolete paper TCS in 2013. PGE projects a reduction in payroll costs of

$1.0 million, which is reflected in wages and salaries in both 2013 and 2014. myTime is explained in more detail in PGE Exhibit 1000, Section II, Part C.

- Information Technology (IT) Vision Design is a roadmap of 15 initiatives directed at improving IT's effectiveness, capabilities, and efficiency over the next three years. Each initiative encompasses one or more of the following six foundational principals: partner with the business; eliminate complexity; source strategically; standardize IT process/procedures; build a strong workforce; and, meet increasing service expectations. Through the 15 initiatives, IT will be able to continue supporting PGE's growing need for technical infrastructure and services while maintaining a relatively flat IT employee count. From 2011 through 2014, we project a net reduction of 7.8 IT FTEs. See PGE Exhibit 600, Section III, Part B for details.
- Generation Excellence. In 2006, PGE's generation organization established the Generation Excellence initiative to focus on improvement efforts such as safety, employee performance, process improvements, and reliability. Generation Excellence has continued to evolve with the establishment of Reliability and Maintenance Excellence (R&ME), which is a comprehensive approach to reliability and maintenance; it encompasses, and better aligns, several sub-initiatives including Reliability Centered Maintenance (RCM) and utilization of our Enterprise Work and Asset Management System (Maximo). R&ME is plant specific and each plant is anticipated to have their strategy in place by the end of 2013. For more detail see PGE Exhibit 700, Section III, Part A.

III. Efficiency and Effectiveness in Operations

Q. Is PGE also implementing changes in operational day-to-day activities that lead to lower costs?

A. Yes. We have several operational methods that reinforce efficiency and cost effectiveness in our daily operations including: budget development and management as well as goods and services procurement.

Q. How does PGE reinforce efficiency and effectiveness through its budget process?

A. The goal of PGE's budget process is to allocate limited resources to achieve our corporate goals of delivering safe, reliable power and effective customer service. Our budget process reflects our commitment to an efficient use of resources to effectively deliver safe and reliable power.

Q. How do O&M budgets reflect a commitment to efficiency and cost effectiveness?

A. Our O&M budget process relies on managers who know their areas of responsibility, including how the work is performed and the resources required to perform it. With officer guidance, managers develop their budgets while also identifying variances from the previous year's budget. Proposed budgets are then reviewed by senior managers and officers, and finally PGE's Board of Directors. Officers review actual results compared to budget on an income statement line-item basis. On a regular basis, analysts and managers monitor actual expenses and revenues, taking timely corrective action in response to deviations. The budget reports as well as management and executive reviews serve as controls during the budget year. Again, our process reflects our commitment to an efficient use of resources to effectively deliver safe and reliable power.

Q. How do capital budgets reflect a commitment to efficiency and cost effectiveness?

A. PGE uses a cross-functional group of senior PGE managers called the Capital Review Group (CRG) to review proposed capital projects (except major projects such as T&D Transformation and Customer Engagement Transformation, which are evaluated at the Officer and/or Board levels). Funding Project documentation must be submitted for each project and includes the scope, justification, and cost of the project. The CRG prioritizes projects and recommends to the CEO which ones should proceed. Prioritization is primarily based upon necessity (i.e., projects that are required to remain in regulatory or contractual compliance or avoid system obsolescence). Other factors that the CRG considers are urgency, consequences, economic value, and alignment with corporate strategy. Project approval and prioritization ensures that plans to commit resources are thoroughly scrutinized, appropriately authorized, monitored and adequately reviewed upon completion. If the project scope changes significantly after approval, the project is again reviewed.

Q. How does PGE reinforce efficiency and cost effectiveness through procurement processes?

A. PGE's general procurement strategy uses a competitive process led by the Sourcing and Contracts team of specialized buyers. The buyers are familiar with vendors, products, and services as well as current market conditions. By using PeopleSoft (part of FSRP) as PGE's primary supply chain software in conjunction with Oracle Business Intelligence (OBI), a reporting tool, PGE is able to perform "spend analysis" to combine similar purchases and leverage PGE's buying power through strategic sourcing. PGE buyers now better understand what PGE purchases across the enterprise. Additional information on Procurement's strategic sourcing process is provided in PGE Exhibit 1000, Section II, Part A.

For significant purchases, we encourage the use of formal bidding. Construction projects with defined scopes of work and available contractors are nearly always bid, although the type of the contracts may differ. Bids are evaluated based on total ownership cost.[2] However, cost of the good or service, while important, is not the only factor considered. For example, fleet purchases, (e.g., hybrid or specialized equipment) may have other factors such as the uniqueness of the required product. In software purchases, factors like maintenance or replacement may significantly influence the purchasing strategy. In these cases, users are required to justify single or sole sources for the purchase. In many areas, procurement decisions are a collaborative effort with the department that uses the good or service.

Q. Please summarize your testimony.

A. Operational excellence is an integral part of strategy at PGE. Since 2009, we have made progress in centralizing and developing our continuous improvement cycle, which will continue to evolve. The product of our hard work can be seen in over $15 million of O&M savings and avoided costs projected for the 2014 test year. By mitigating rising costs while maintaining effectiveness, we work to keep our prices lower than otherwise. We are proud of our history of effectiveness as described in the PEG benchmark study. It is our responsibility to run an efficient operation for customers, while not sacrificing safety and high reliability and meeting growing customer expectations. For more information on how PGE is working to meet customers' future needs see PGE Exhibit 900.

[2] Total ownership cost is a comprehensive systems approach to analyzing purchases, processes, and supply chain-related decisions.

IV. Qualifications

Q. Ms. Pope, please describe your educational background and experience.

A. I received my Bachelor of Arts degree from Georgetown University in 1987 and my Master's degree in Business Administration from the Stanford University Graduate School of Business in 1992. I was named Senior Vice President, Chief Financial Officer and Treasurer of PGE in January 2009. From January 2006 through December 2008, I served on the PGE Board of Directors. Previous to January 2009, I served as Vice President, Chief Financial Officer at Mentor Graphics Corp., an Oregon-based software company, where I was responsible for multiple departments including the company's financial affairs, corporate development and operations. Before I joined Mentor Graphics in 2007, I served 12 years in a variety of capacities at Pope & Talbot, Inc, and worked previously at Morgan Stanley.

Q. Ms. Neitzke, please describe your educational background and experience.

A. I received my Bachelor of Science degree in Business Administration with an emphasis in Finance from Oklahoma State University in 1984 and my Post-Baccalaureate Accounting Certificate (PBAC) from Portland State University in 1997. I have worked for PGE since 2007 in various managerial positions including Financial Reporting Group, Assistant Treasurer and Director of Planning and Performance Management. From 1998-2007, I was a Senior Manager in the audit practice of KPMG LLP, Portland office. From 1992-1997, I was a credit analyst for First Interstate Bank; and from 1984-1990, I was in a similar credit analyst role at the Bank of Oklahoma.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
201	O&M Efficiency Summary
202	Corporate Performance Benchmarking to Date
203	Projected Benchmarking Cycle

Test Year: 2014
O&M Efficiency Summary
(in $ millions)

Initiative	2014 Savings	PGE Exhibit Location
1. A&G - Procurement Efficiency via Strategic Sourcing [1]	1.1	Exhibit 1000 Section II Part A
Utilizing FSRP and strategic sourcing methodology, Procurement has become more efficient		
2. F&A - Financial System Replacement Project (FSRP) and Work Process Analysis [2]	1.5	Exhibit 1000 Section II Part A
Replacement of obsolete financial system. By utilizing new technology and analyzing work processes a net 15.3 FTE reduction is achieved by 2014.		
3. F&A - 1% Rebate on P-Card Purchases	0.1	Exhibit 1000 Section II Part A
Pge receives annual lump sum rebates from Bank of America for using corporate credit cards for business purchases		
4. HR - Net Reduction of 9.3 FTE [2]	0.8	Exhibit 1000 Section II Part C
Lean Processing implementation and the leverage of technology contribute to HR's ability to reduce and redeploy FTEs by streamlining workflow and reducing resources needed to complete work processes		
5. HR - myTime	1.0	Exhibit 1000 Section II Part C
Replacement of obsolete time collection system with web-based system		
6. HR - Employee Benefit Mitigation Efforts		
In-source health and welfare administration	0.3	Exhibit 500 Section IV
Self-Insured MetLife Dental [1]	0.1	Exhibit 500 Section IV
Higher Deductibles, Increased Co-Pays	0.8	Exhibit 500 Section IV
Vendor Change for Pre-1992 Non-Union Medicare Supplemental Plan	0.7	Exhibit 500 Section IV
401(k) Administration Provider Change	0.8	Exhibit 500 Section IV
7. IT - Vision Design [2]	0.8	Exhibit 600 Section III Part B
IT will continue to support PGE's growing need for infrastructure while achieving a net reduction of 7.8 IT FTE		
8. IT - Application Management	0.6	Exhibit 600 Section III Part B
Rationalizing outstanding applications and eliminating duplicative functions		
9. IT - Agile Initiatives [3]	0.4	Exhibit 600 Section III Part B
Through Agile Initiatives, IT has been able to eliminate contract labor needs for IT application support		
10. IT - Virtual Servers [1] [4]	3.3	Exhibit 600 Section III Part B
Utilizing virtualized servers over physical servers		
11. T&D - Transformation O&M Savings		
Centralization and standardization of work processes, as well as, intergration of technology in an effort to improve safety, accountability, standardization, productivity and efficiency		
Centralization of Regional Line Dispatch	0.5	Exhibit 800 Section II Part C
Off - Shift Crews	0.7	Exhibit 800 Section II Part C
Supervisor in the Field (SITF)	0.8	Exhibit 800 Section II Part C
Fleet Optimization	0.2	Exhibit 800 Section II Part C
Service Coordinator	0.1	Exhibit 800 Section II Part C
Other	1.2	Exhibit 800 Section II Part C
2014 O&M Efficiency Savings	$ 15.6	

Footnotes:

(1) *Avoided cost savings*

(2) *Based on FTE reductions for each business area, which can include redeployment. For net reductions by operating area, please see PGE Exhibit 501. Benefits are calculated using average W&S for each respective area.*

(3) *Calculated based upon savings realized since the inception of intiative (2010 - 2014)*

(4) *Calculated on a 1:1 basis*

Benchmarking to date

Function	Vendor	Data Year	Reported
Finance & Accounting*	PWC & Hackett Group	2009	Q1 -2011
Human Resources	Hackett Group	2009	Q3 - 2010
Transmission & Distribution	First Quartile Consulting	2010	Q4 - 2011
Generation	Navigant Consulting	Thermal: 2007-2009	Q2 -2011
		Hydro: 2009	Q2 -2011
		Wind: 2008-2010	No Report Out - limited Data
Information Technology	Hackett Group	2011	Q3 - 2012
Customer Service	PA Consulting	2011	Q4 -2012
Shared Services**	Utility Sponsored (PSEG)	2011	In Process
Public Policy	Internal Review	2012	In Process
Legal	HBR Consulting	2010 - 2011	In Process

* Includes Mid-Back Office Survey completed in 2012

** Includes functions such as: Regulatory, Security, Facilities, Communications, Community & Government Relations

Portland General Electric

Projected benchmarking schedule

Re-evaluating benchmarking schedule, determining appropriate cycles for each organization and centralizing benefit tracking in 2013

2013	2014	2015	2016
Fleet	Finance	Transmission	Customer Services
	Human Resources	Distribution	IT
		Generation	Public Policy
		Legal	

Note: Difficult to project what departments will be captured within each study. For example, depending on study taxonomy, Meter Reading could be captured in a Transmission & Distribution or Customer Service study.

Portland General Electric

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 262

Revenue Requirement

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Alex Tooman
Christopher Liddle

February 15, 2013

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I. Introduction

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

A. My name is Alex Tooman. I am a project manager for PGE. I am responsible, along with Mr. Liddle, for the development of PGE's revenue requirement forecast. In addition, my areas of responsibility include results of operations reporting, power cost adjustment mechanism filings and other regulatory analyses.

My name is Chris Liddle. I am also a project manager for PGE. My areas of responsibility include revenue requirement and other regulatory analyses.

Our qualifications are included at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to present PGE's $1,785.3 million revenue requirement for the 2014 test period. On an average rate base of $3,126.2 million, this revenue requirement will allow PGE an opportunity to earn a 7.863% rate of return that includes a 10.0% return on average common equity of 50.0% in 2014. PGE Exhibit 301 summarizes the development of PGE's 2014 revenue requirement.

In addition to presenting this integrated or bundled revenue requirement, we also present and discuss our unbundled revenue requirement in Section VIII.

Q. What increase in rates does PGE request in this proceeding?

A. PGE is requesting an increase of $104.8 million or 6.2% including changes to base rates as well as Schedule 145 (Boardman decommissioning, see PGE Exhibit 1500). This increase is relative to the revenues we would expect based on 2013 prices, which reflect approved rates in UE 215, UE 228, UE 249, and UE 250. Therefore, PGE requests that base rates be adjusted on January 1, 2014, to yield $102.5 million of additional revenues on an annualized basis plus an additional $2.3 million to be recovered via Schedule 145. This base rates request includes approximately $26.8 million of revenue requirements associated with capital projects that were subject to a deferral authorized in UE 215 (capital deferrals). These revenue requirements would likely be recoverable absent this filing. Thus, the net impact is approximately $78.0 million or 4.8%.

Q. Is capital investment a driver for this rate case?

A. Yes. In addition to continued "base business" investment of over $200 million per year, PGE is investing in other key projects including a surface water collector at its River Mill facility pursuant to the Clackamas License, the Avery building that will house consolidated dispatch and other functions (PGE Exhibit 100), the Readiness Center for critical response and recovery functions (PGE Exhibit 600), and SO_2 controls at Boardman (PGE Exhibit 700). Though rate base is flat relative to UE 215, these capital investments and their associated O&M costs are meaningful drivers of the request in this case, generating an estimated $12 million of revenue requirement excluding the capital deferrals. Offsetting PGE's $149 million increase in net utility plant is a $157 million increase in PGE's accumulated deferred taxes driven by bonus depreciation and investments in software of which the majority is expensed immediately for tax purposes.

Q. Were actions taken to help limit the size of the requested increase?

A. Yes. We adjusted the revenue requirement to reflect the three items described in PGE Exhibit 100. The approximate revenue requirement impact of the adjustments total $29.5 million of reductions, as follows:

- Reducing our requested incentive costs: $(12.4) million.

- Including a balancing account for pension-related costs: $(14.5) million (PGE Exhibit 500)
- Inclusion of steam turbine and generator inspection costs into a proposed major maintenance accrual for Port Westward: $(2.6) million

Additionally, we are requesting an ROE of 10%, which is at the low end of the recommended range as discussed in PGE Exhibit 1200.

Q. In addition to approving PGE's proposed 2014 revenue requirement, what else is PGE requesting in this case?

A. PGE requests that the Commission provide several accounting orders that would help temper the volatility of costs and customer prices, including:

- Storm deferral accrual – a continuation of an accounting order granted in UE 215, with a modification. Currently, PGE is allowed to include in rates approximately $2 million each year that accrues in a storm damage restoration account that can be used to help offset future major storm damage. PGE requests that the accrual be treated as a balancing account, such that major storm damage costs in excess of what has been collected so far be included in the balancing account and offset over time by future accruals.
- Pension – PGE includes a balancing account mechanism discussed in PGE Exhibit 500 that includes pension expense and a return on its prepaid pension asset. We propose this balancing account be amortized over 15 years to minimize the impact to customers while providing recovery for prudently incurred costs.
- Maintenance accrual – PGE proposes a major maintenance accrual for Port Westward similar to the one in place for Coyote Springs. Such an accrual smoothes cost and recovery for customers and ensures they only pay for costs incurred. We have included a

steam generator and turbine inspection at Port Westward in this accrual to reduce our request in this case.

A. PGE Results if No Rate Increase is Authorized

Q. In the absence of a rate increase, what is PGE's expected regulated ROE for 2014?

A. As shown in column 1 of PGE Exhibit 301, without a rate increase we would expect PGE's ROE to be approximately 6.2% in 2014, significantly lower than its authorized ROE of 10.0%. This assumes recovery of the capital deferral described earlier continues. However, in the absence of a rate case PGE's proposed pension balancing account and Port Westward maintenance accrual would not exist, therefore PGE's ROE would be 5.9%.

B. Structure of the Case

Q. Does PGE's 2014 revenue requirement include the effect of any new generation or transmission resources?

A. PGE expects substantial generation capital additions as a result of the ongoing request for proposals (energy, capacity and renewables) and has included forecasted expenditures to estimate the need for additional debt and equity financing. PGE expects to learn by the end of the second quarter of 2013 the specifics of the capital additions and will adjust the financing assumptions in its revenue requirement accordingly.

Similarly, PGE has included an estimate of capital expenditures associated with the Cascade Crossing transmission project (Cascade Crossing) and its associated impact on PGE's financing assumptions. PGE and the Bonneville Power Administration recently announced the pursuit of modifications to PGE's proposed Cascade Crossing; capital expenditures are subject to change as a result. PGE may adjust the associated financing costs in its revenue requirement if new information becomes available.

Q. Does the rate case incorporate other capital investments recovered through means other than base rates in the recent past?

A. Yes. As discussed, our 2014 revenue requirement in this case includes the costs and benefits of PGE's four capital investments that were previously deferred beginning with the prior general rate case (UE 215). In addition, this case includes PGE's investment in the Baldock solar facility. The Commission recently approved PGE's investment in this facility in UE 249, with a deferral in 2012 and revenue requirement for 2013 with rates in effect January 1, 2013 through Schedule 122.

Q. Please summarize PGE's 2014 revenue requirement.

A. Table 1 below summarizes PGE's 2014 revenue requirement by major category and provides a comparison to regulated utility actual results from 2011. We also list the PGE testimony that addresses the specific cost categories.

Table 1
(Revenue Requirement Summary in $millions)

Rev Req Category:	2011 Actuals	2014 Test Year*	Exhibit	No.
Sales to Consumers	$1,731,156	$1,785,274	Rev Req	300
Other Revenue	$21,477	$21,396	Rev Req	300
NVPC	$689,904	$639,194	Power Costs	400
Production O&M	$110,903	$121,983	Production	700
Transmission O&M	$11,463	$12,150	T&D	800
Distribution O&M	$79,604	$93,824	T&D	800
Customer Service	$68,089	$81,347	Customer Svc.	900
A&G	$147,532	$156,757	IT / Corp. Support	600, 1000
Depr. & Amort.	$225,646	$275,026	Rev Req	300
Other Taxes	$96,561	$110,670	Rev Req	300
Income Taxes	$70,162	$69,908	Rev Req	300
Operating Income	$252,770	$245,809	COC	1100
ROE	10.69%	10.0%	ROE	1200

*excludes Sch. 145 Boardman Decommissioning

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

A. Operating Income consists of a return to the providers of capital to PGE, both equity and debt. The costs of obtaining capital are discussed in PGE Exhibits 1100 and 1200.

Q. How did you develop the 2014 revenue requirement?

A. We developed the 2014 revenue requirement based on PGE's 2013 budgets. The 2013 budgets are escalated for inflation and adjusted (both increases and decreases) for known and measurable changes. PGE Exhibit 200 describes PGE's benchmarking efforts and the steps taken to maximize organizational efficiency to mitigate the proposed rate increase, in addition to the management discretionary items previously described.

Q. What rates did you use to escalate the 2013 budget to 2014?

A. We applied the following escalation rates to the 2013 budget:

- Union labor – 2.0% effective March 1
- Non-union labor – 3.0% effective April 15 for non-exempt, non-officers and for officers
- Outside services (PGE cost elements (CE) 1502, 1602, 2200, 2300) – 2.4% effective January 1
- Direct materials (CE 2101, 2110) – 1.5% effective January 1
- Employee business expense (CE 2400, 2701) – 1.8% effective January 1

Q. What are the sources of these escalation rates?

A. For outside service, direct materials and employee business expense, we use escalation rates from the Global Insights, U.S. Economic Outlook dated October 2012. Wage escalation is based on the forecast of compensation costs described in PGE Exhibit 500.

Q. Did you adjust PGE's 2014 revenue requirement to reflect previous ratemaking decisions and other regulatory policies?

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

Table 2
(Regulatory Adjustments in $millions)

Rev Req Category:	O&M	Rate Base
Retail Services	$(0.1)	$(0.3)
Charitable Contributions	$(1.1)	
State & Federal Lobbying	$(1.0)	
Memberships and Dues	$(0.2)	
MDCP	$(5.3)	
SERP	$(1.5)	
Image Advertising	$(0.8)	
Total Adjustments	$(10.0)	$(0.3)

Q. Please explain these regulatory adjustments.

A. Here is a brief overview:

- Charitable contributions: excluded the entire $1.1 million from cost of service;
- State and federal lobbying: excluded the entire $1.0 million from cost of service;
- Memberships and dues: removed approximately $0.2 million, which reflects the rate making treatment received in UE 197 and UE 215;
- Managers Deferred Compensation Plan (MDCP): removed the entire $5.3 million from cost of service;
- Supplemental Executive Retirement Plan (SERP): removed the entire $1.5 million from cost of service;
- Corporate image advertising: removed the entire $0.8 million from cost of service.

Q. What comparisons of test year costs do you make in the testimonies generally?

A. We compare our forecast of 2014 test year costs to 2011 actual costs. We perform these comparisons because 2011 was the last full year of actual cost information available at the time this filing was prepared.

II. Other Revenue

Q. What is PGE's 2014 forecast of Other Revenue and how does it compare with prior years?

A. PGE forecasts 2014 Other Revenue of $21.4 million. This compares to 2011 actual other revenue of $22.4 million.

Q. What are the sources of Other Revenue?

A. The primary sources of Other Revenue are rent of electric property, transmission revenues, joint-pole revenues, steam sale revenues, ancillary service revenues, and miscellaneous charge revenues. PGE Exhibit 302 provides the sources and amounts of other revenue, summarized in Table 3 below.

Table 3
(Other Revenue in $millions)

Rev Req Category:	2011 Actuals	2014 Forecast
Utility Property Rental	$6.8	$6.5
Intertie/Other Transmission	$6.1	$5.7
Late Payment Interest	$1.9	$2.6
Steam Sales	$1.7	$1.6
Other Misc. Revenues	$6.0	$5.0
Totals	$22.4	$21.4

Q. Did you make any adjustments related to Other Revenue for the 2014 test year?

A. Yes. We adjusted the 2014 forecast of transmission revenues received from Energy Service Suppliers (ESSs). The adjusted amount reflects PGE's current Open Access Transmission Tariff (OATT) rate and the forecasted ESS activity for 2014.

III. Depreciation

Q. What is PGE's estimate for 2014 depreciation expense?

A. We estimate $242.9 million in depreciation expense for the 2014 test year. PGE Exhibit 303 summarizes the test year depreciation expense by plant type and provides a comparison to actual 2011 depreciation amounts.

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

A. No. PGE's UM 1458 Depreciation Study was filed in 2009, and the results of the study, which were implemented in January 2011, remain valid at this time. We expect to file a new study in 2014, in line with our 5-year cycle.

Q. Is your estimate of 2014 depreciation expense consistent with the results of the depreciation study filed in UM 1458 and Commission Order No. 10-355?

A. Yes.

Q. What are the primary drivers of the $25 million increase?

A. The primary drivers of the increase are $10.8 million at Boardman related to Schedule 145 and capital additions, $8.2 million related to distribution property capital additions, $8.3 million related to general plant capital additions, $3.0 million for other plant, and a $5.0 million decrease related to Biglow Canyon.

Q. What closure date has PGE assumed for Boardman in this filing?

A. We use a 2020 end-of-life assumption for Boardman to develop the base revenue requirement in this case.

Q. Does PGE propose to continue to use Schedule 145?

A. Yes, but only to separately identify and collect the projected costs of Boardman decommissioning as explained in PGE Exhibit 1500.

IV. Amortization

Q. What is amortization?

A. Amortization, like depreciation, is a means to allocate the cost of an asset over its useful life, but amortization relates to intangible assets, such as computer software and regulatory assets. As with depreciation expense, the unamortized balance of the associated assets generally appears in rate base and earns a return at the allowed rate.

Q. Please summarize PGE's 2014 amortization expense.

A. PGE Exhibit 304 details the total 2014 amortization expense of $32.1 million, which we summarize in Table 4 below.

Table 4
(Amortization in $millions)

Amortization Item:	2011 Actuals	2014 Test Year
Software Amortization	$13.2	$18.6
Other Intangible Amortization	$6.1	$3.2
Trojan Decommissioning	$3.5	$3.5
Other Reg Debit Amortization	$7.6	$12.7
Other Reg Credit Amortization	$(6.7)*	$(5.9)
Total Amortization	$23.7	$32.1

*excludes $18.1 million credit for ISFSI tax credits

Q. Please explain the amortization of software included in PGE's 2014 amortization expense.

A. Total software amortization is $18.6 million, which represents the amortization of capitalized software, and is generally amortized over a 5 year period.

Q. Why is software amortization $5.4 million higher in 2014?

A. The largest drivers for the increase are software additions for the 2020 Vision Project and Advanced Metering Infrastructure. The increase in amortization was partially offset by amounts fully amortized between 2011 and 2014, the largest of which were PGE's Customer

Information System, Energy Management System, Web Initiative software, and Contact Center software.

Q. Please describe Other Intangible amortization.

A. Other Intangible amortization includes hydro relicensing amortization and miscellaneous other intangible plant amortization. For hydro relicensing, this represents the recognition of annual costs associated with non-construction projects that have closed to plant in service. Generally, these costs are amortized over the life of the new license. PGE Exhibit 700 further describes these capital costs.

Q. Why is Other Intangible amortization approximately $2.9 million lower in the 2014 test year than 2011 actual results?

A. Amortization related to Biglow Canyon that was present in 2011 is fully amortized prior to 2014.

Q. Please describe the change in Other Regulatory Debits.

A. Other Regulatory Debits increase from 2011 to 2014 primarily due to the addition of the Port Westward major maintenance accrual of $4.9 million and an increase to the Coyote Springs major maintenance accrual of $2.4 million. This is offset by $0.4 million associated with equity issuance fee amortization and other miscellaneous decreases.

Q. Please summarize the outcome from the last docket in which PGE changed its Trojan Nuclear Decommissioning Trust (NDT) collection rate (UE 215).

A. In Order No. 10-478 (UE 215), the Commission authorized the annual amount collected in rates for the NDT to be reduced from $4.65 million to $3.5 million.

Q. Did PGE recommend any changes in the amount to be collected from customers in its last general rate case (UE 215)?

A. Yes. We performed an analysis of the annual accrual, updated for the latest NDT balances, expected rate of return on trust assets, cost estimates, and other parameters. This analysis indicated that a change to the lower collection rate was appropriate.

Q. Does PGE recommend any changes to the current $3.5 million collection rate?

A. Not at this time. We recently updated the analysis described above, and recommend that no change be made. Based on this analysis and the considerable uncertainty associated with the spent nuclear fuel at the Trojan site, PGE proposes to maintain the annual accrual rate of $3.5 million.

Q. Please elaborate on the uncertainty.

A. Costs associated with the dry storage of spent nuclear fuel at the Trojan site are the largest remaining decommissioning costs. The future of the permanent location for spent fuel has been uncertain for years as the development and opening of the Yucca Mountain repository has been subject to continued delays. In early 2010, the Obama Administration announced its intent to terminate the Yucca Mountain project and convened a Blue Ribbon Commission on America's Nuclear Future to develop and examine alternatives. This commission generated a report in early 2012 containing a series of recommendations including one to give priority to enabling the transfer of "stranded" spent nuclear fuel from shutdown plant sites such as the fuel at Trojan. In January 2013, the U.S. Department of Energy issued a report which endorses giving priority to accepting fuel from shutdown plant sites. However, implementation of the Blue Ribbon Commission recommendations requires legislation and appropriate authorizations from Congress, and no action has yet been taken. Given the continued delays in the U.S. Department of Energy taking possession of Trojan's spent nuclear fuel, it is appropriate to support an accrual rate of $3.5 million per year.

Q. Please describe the recent ruling by the U.S. Court of Federal Claims relating to spent nuclear fuel storage.

A. On November 30, 2012, the U.S. Court of Federal Claims ruled that the owners of the Trojan Nuclear Plant (including PGE) are entitled to compensation from the federal government related to spent nuclear fuel storage through 2009[1]. The judgment does not state the precise amount of the damages award, but directs the parties to consult and propose a final amount for the owners' recovery that is based on certain adjustments specified in the court's ruling. The date for this proposal has been delayed, but is expected to be by late in the first quarter of 2013. PGE estimates that the total amount of the award, as calculated pursuant to the judgment, will range from approximately $60 million to $70 million. Any award amount would be allocated to the three owners on a pro-rata basis in accordance with their respective ownership share of Trojan, with an adjustment for PGE for a state tax credit. Accordingly, PGE's share of that amount would be 67.5 percent. However, PGE expects the U.S. Department of Energy to appeal this ruling in early 2013.

Q. What is PGE's intent should the judgment above be upheld and a damage amount determined?

A. Since PGE customers have paid for the Trojan decommissioning activities, any awarded amounts received by PGE would benefit our customers likely by returning it to the decommissioning trust.

Q. What decommissioning activity has been accomplished since UE 215?

A. The majority of the structures at the facility have been demolished. PGE is preparing the Trojan North and Trojan Training buildings for decommissioning, and demolition is

[1] PORTLAND GENERAL ELECTRIC COMPANY, CITY OF EUGENE, OREGON, acting by and through the EUGENE WATER AND ELECTRIC BOARD, and PACIFICORP v. THE UNITED STATES, COFC No. 04-09C, November 30, 2012.

expected to take place in 2014. Beyond this, PGE has no further planned decommissioning demolition work until after the spent nuclear fuel has been removed from the site.

Q. Has the Colstrip Common Facilities amortization changed for 2014?

A. No. We are continuing to amortize this asset as required under prior Commission order.

Q. What is the Coyote Major Maintenance Accrual and Amortization?

A. In UE 93 (OPUC Order No. 95-1216), the Commission approved an accrual and balancing account treatment for Coyote's major maintenance costs. The major maintenance accrual is based on a multiple-year forecast of major maintenance activities with an accrual estimate designed to bring the balancing account to zero at the end of the multiple-year period. In UE 180, the Commission approved updating the annual accrual to $2.0 million.

Q. Do you propose to change the Coyote major maintenance accrual for 2014?

A. Yes. We are proposing to update the amortization and associated rate base amounts to reflect historical and projected maintenance activity at the plant. PGE is including amortization of $4.4 million and an associated rate base adjustment of $0.2 million. This is an increase from the $2.0 million amount last updated in PGE's UE 180 proceeding. Prior to the update in UE 180, this amount was set at approximately $4.1 million.

Q. Do you propose a Port Westward major maintenance accrual for 2014?

A. Yes. We propose an amortization of $4.9 million and an associated rate base adjustment of $2.5 million to reflect projected maintenance activity at the plant.

Q. Has PGE included any major maintenance activities that are not part of the Port Westward Long-term Service Agreement?

A. Yes. In 2014, major inspections of the steam turbine and steam turbine generator will be conducted. The cost of these inspections is approximately $3.1 million, which has been included in the maintenance accrual, reducing the test year revenue requirement by approximately $2.6 million.

Q. Has PGE included a forecast of property sale gains for the test year?

A. No. We continue to support the use of the deferral mechanism originally approved in UE 115 for actual utility property sale gains and losses. Since actual gains/losses will be deferred and refunded/collected through a supplemental tariff, we do not include any cost of service reduction in the 2014 test year.

Q. What are equity issuance fees?

A. Equity issuance fees are the costs associated with issuing additional shares of common equity. As discussed in PGE Exhibit 1100, PGE anticipates issuing $375 million of equity in 2013 to support expected investment in energy, capacity, and renewable resources. PGE estimates the fees at 3.5% of the issue total, or roughly $13.1 million in 2013. Further, equity issuance costs are recorded on the balance sheet as reductions in shareholder equity under GAAP and are not expensed for either book or tax purposes.

Q. What is PGE's proposed rate making treatment of equity issuance fees in this proceeding?

A. PGE proposes to treat the 2013 equity issuance fees as a regulatory asset for rate making purposes and amortize them over a 10-year period; consistent with the treatment provided by the Commission in UE 197 and UE 215. PGE is already amortizing existing equity issuance fees at a rate of approximately $1.7 million per year. The remaining balance will be added to the fees associated with the 2013 equity issuance, which will subsequently be amortized over a 10-year period beginning with 2014. Thus, we have reset equity issuance expense to approximately $1.3 million and have added a regulatory asset to our rate base to reflect the average unamortized balance in 2014. Finally, to recognize the non-tax deductible nature of these fees, we have added a permanent book-tax difference to the derivation of income tax expense in the test year.

Q. Did PGE issue equity in 2011 as contemplated in UE 215?

A. No. However, the balance of equity issuance fees from 2009 has been amortized at the rate of $1.7 million per year as established in UE 215. As a result, the unamortized balance at the end of 2012 was $1.76 million, and will be $0.06 million by year end 2013.

Q. Why did PGE not issue equity in 2011?

A. The $300 million equity issuance contemplated in UE 215 was based on anticipated capital expenditures primarily related to the RFPs and other capital projects. PGE encountered significant delays predominantly related to the process for the RFPs. This has effectively delayed the equity issuance until 2013 and prompted its inclusion in this rate proceeding. PGE expects to learn whether it will have significant capital additions as a result of the RFP process and will make the appropriate changes to its financing plans, including reducing the amount of equity, as needed. These changes will be reflected in PGE's revenue requirement request in this case.

Q. Why is PGE proposing a multi-year recovery schedule for equity issuance fees in this case?

A. We propose this approach here to smooth the impact of the sizable equity issuance offering expected in 2013 and to better match the recognition of costs with the expected benefits of the capital projects that the equity will help finance. As noted earlier, it is also consistent with prior practice.

V. Income Taxes, Taxes Other than Income

A. Income Taxes

Q. What is PGE's 2014 estimate of income taxes?

A. PGE's 2014 test period income tax expense forecast is $69.9 million. PGE Exhibit 305 details the test year calculations of income tax expense and provides a comparison to previously authorized income tax assumptions. This compares to Commission-authorized utility income tax expense of $57.3 million based on approved rates. The increase in 2014 test year income tax expense compared to current rates primarily reflects increased tax expense due to a higher Oregon state tax rate reflected in this case, and reduced federal tax credits.

Q. Does PGE expect any tax benefits as the result of consolidated tax reporting in the next few years?

A. No.

Q. What methodology did you use to establish estimated income tax expense for the 2014 test year?

A. We use the "stand-alone" method to determine the test year income tax expense. This method uses as inputs only those costs and revenues included in our requested test year revenue requirement to determine the income tax expense for the test year. The Commission has traditionally used this approach to determine the income tax expense in test year rate making.

Q. What income taxes does PGE pay?

A. PGE pays income taxes to the federal government, States of Oregon, Montana and California, and to local government entities such as Multnomah County.

Q. What are the marginal tax rates for PGE?

A. The federal marginal tax rate is 35.00%, the State of Oregon marginal tax rate is 7.55%, the State of California marginal tax rate is 8.84%, and the State of Montana marginal tax rate is 6.75%.

Q. What is PGE's state composite tax rate for this filing?

A. PGE's composite state tax rate is 7.474%. The rate is a function of the marginal state tax rates and the respective allocation factors of taxable income to different state jurisdictions.

Q. Is the state composite rate different than it was in UE 215?

A. Yes. In UE 215, the state composite tax rate was 6.242%. In this proceeding, we have adjusted the figure upward to 7.474% to reflect higher apportionment for Oregon based on recent actual results.

Q. What is PGE's total composite tax rate for this filing?

A. PGE's total composite tax rate for this filing is 39.858%. It is the sum of the federal marginal tax rate and the state composite tax rate, less the effect of their interaction, or:

$$35.00\% + 7.474\% - (35.00\% * 7.474\%) = 39.858\%$$

Q. Why did you exclude tax rates from local jurisdictions from the calculation of the composite tax rate?

A. PGE collects Multnomah County Business income taxes through a supplemental tariff to comply with OAR 860-022-0045. As such, we do not include an estimate of the costs as part of our revenue requirement in this proceeding.

Q. Did you include state and federal tax credits in your estimate of income tax expense for 2014?

A. Yes. We included $2.5 million of state Business Energy Tax Credits (BETC), $0.5 million of non-Independent Spent Fuel Storage Installation (ISFSI) state pollution control tax credits, and $25.2 million of federal National Environmental Policy Act (NEPA) credits in the estimate of 2014 test year income tax expense. Both the BETC state tax credits and the federal NEPA credits are earned from PGE's Biglow Canyon wind projects.

Q. How did PGE establish its forecast of federal NEPA credits?

A. PGE based its forecast on historical actual credits from 2011 and 2012. PGE averaged these results to forecast for the 2014 test year.

Q. Why did you exclude ISFSI state tax credits from the derivation of 2014 income tax expense?

A. As of 2013, PGE is no longer receiving these state tax credits and has completed the 10 tax-year deferral (per UM 1186). Customers have received, or will receive, the benefit of these credits through the deferred treatment as PGE is able to utilize them.

B. Taxes Other Than Income & Fees

Q. What is PGE's 2014 estimate of Taxes Other Than Income and Fees?

A. As shown in PGE Exhibit 306, total Taxes Other Than Income are $110.9 million. This compares to 2011 actual costs of $96.6 million. The individual sources of increased costs from the 2011 actuals to the 2014 test year are:

- Franchise Fees: from $40.6 million to $44.7 million;
- Payroll Taxes: from $12.6 million to $14.1 million;
- Property Taxes: from $41.7 million to $50.4 million; and
- Other miscellaneous fees: from $1.7 million to $1.8 million.

Franchise Fees

Q. How did PGE estimate franchise fees?

A. We evaluated the expected level of franchise fees based on estimated 2014 gross revenue in jurisdictions charging franchise fees and applied a 3.5% rate to those gross revenues. Based on OAR 860-022-0040, cities may charge up to 3.5% of gross revenue that will be included in PGE's revenue requirement and charged to all customers. Assessments up to 5.0% of gross revenue are allowed, but the incremental fees above 3.5% are charged to customers through a separate charge on the bill payable only by customers in the assessing jurisdiction(s).

Q. Are franchise fees included in PGE's net to gross factor for calculating revenue requirement?

A. Yes. Consistent with the unbundling requirements of OAR 860-038-0200, we separately itemize the impact of our incremental revenue needs on franchise fees in order to directly assign all franchise fees to the Distribution function. The franchise fee rate used to determine this revenue-sensitive cost is 2.501%, nearly identical to the rate of 2.517% authorized in UE 215.

Q. Why have franchise fees increased between current rates and the 2014 test year?

A. Franchise fees have increased due to the impact of PGE's requested increase in this proceeding.

Payroll Taxes

Q. What are payroll taxes?

A. Payroll taxes represent local, state, and federal assessments on wages and salaries. The federal components include FICA (Social Security), Medicare, and Unemployment. The

Oregon components include Worker's Compensation and Unemployment and there is a local withholding for Tri-Met.

Q. How does PGE estimate payroll taxes?

A. PGE estimates payroll taxes by applying an approximate 9.2% payroll tax rate to total wages and salaries. We allocate a portion of payroll tax cost to capital consistent with the allocation of overall capitalized wages and salaries.

Q. Why have payroll taxes increased between 2011 actuals and the 2014 test year?

A. Payroll taxes have increased generally in alignment with wages and salary growth between those years described in PGE Exhibit 500.

Property Taxes

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

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

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

A. Rather than each individual county assessing property tax, Oregon and Montana "centrally assess" PGE's property using a unit approach. This unit approach is required by state statutes because our properties are so thoroughly integrated that valuation of each individual asset would not equal the entire unit value. A piece of wire cannot be valued without looking at its relationship to the entire unitary system. This assessment is done by each state using an average of three approaches to determine value: 1) Cost, 2) Income and 3) Comparable Sales approach. Using an average of these three factors the States then determine an average ("correlated" value). The goal of this valuation process is to assess PGE property as closely as possible to its real market value on January 1st of each year.

Q. How is the first valuation method, the "Cost" approach calculated?

A. Cost approach valuation is calculated using the regulatory calculation for rate base with the following major adjustments:

Plant in Service
+ Construction Work in Progress (CWIP)
+ Materials and Supplies
+ Future Use
+ Contributions in Aid of Construction (CIAC)
- Accumulated Depreciation/Amortization
= Net Cost Valuation

CIAC is traditionally subtracted from plant in service to derive rate base. However, when calculating property taxes, any contribution made by customers for bringing electrical service to their property is taxable, because the property, such as a customer line extension, is ultimately owned by PGE.

Q. Are there other adjustments to the Cost Approach?

A. Yes. The Trojan switchyard is still in use and therefore taxable despite the fact that PGE's Trojan assets were previously written off for book purposes. In addition, any amounts included in plant in service or accumulated depreciation related to Asset Retirement Obligations (SFAS No. 143) are excluded from tax assessment. Lastly, licensed vehicles and deposits on assets not yet onsite are excluded from the cost approach.

Q. What is the second property tax valuation method and how is it used?

A. The second method is the Income Approach. This approach values the utility based on the projected earnings of the Company. This is done under the theory that a prospective buyer would look at the capitalization of the future income stream (cash flow) that the company could produce from its utility property. The value is calculated as: net operating income divided by the capitalization rate less growth. Net operating income includes the probable future average annual net operating income from properties that exist on the assessment date.

Q. How is the capitalization rate determined?

A. Cost of capital is the basis of the capitalization rate, however, it should be noted that capitalization rates for property tax purposes vary by state. A high capitalization rate would reflect a lower valued property.

Q. What is the third assessment valuation method?

A. The third method is the Sales Comparison approach. This method compares similar properties that have sold recently. It is similar to using recent residential home sales in a neighborhood as an indicator of the value of other homes in the same neighborhood. This approach is problematic for large electric utilities due to limited sales activity in the utility industry. Instead, tax authorities estimate sales value by examining the market value of PGE stock and debt. This approach is also difficult to calculate because of the fluctuating nature of stock prices.

Q. Once each of these three approaches determines a value how are they reconciled in order to reach a final assessed value for PGE property?

A. In Oregon the three amounts calculated using these methodologies are reviewed by Department of Revenue personnel and they determine an average value, to some degree relying on their professional judgment. From that value they subtract the market value of out-of-state property.

Montana assigns a weight to each method to develop system value. The state then uses the *Western States Association of Tax Administrators* (WSATA) formula to calculate Montana's portion of system assessed value. The WSATA formula uses cost, operating capacity, and production megawatt hour factors in each state to estimate the percentage of system value to allocate to Montana

Since PGE has very little presence in Washington, the three approaches to value are not used by that state. Washington values PGE property in the state (percentage of KB Pipeline) using historical cost less depreciation of Washington's assets.

Q. Can PGE dispute or appeal assessed values determined by each state?

A. Yes and we do almost every year in Oregon and Montana. For example, for the 2012/2013 fiscal tax year, PGE disputed the original Oregon assessed value of approximately $3.5 billion and was able to receive a reduction of $105.0 million in assessed value. This reduced property tax expense for that year by approximately $1.5 million. Also, PGE was able to reduce its 2012 Montana assessed value by $10.0 million, which resulted in a $0.2 million reduction in property tax expense. Because of the straight-forward valuation methodology in Washington and the very small amount of property taxes paid to that state (less than $50,000 per year) PGE has not appealed recent assessments in Washington.

Q. After the states and PGE have agreed to assessed values, how is the tax liability calculated?

A. PGE provides each state with the allocated cost of all PGE property in each taxing district in each county. There are numerous taxing districts within each county. For example, PGE has property located in 17 Oregon counties, but receives over 800 individual property tax bills. Assessed value is then apportioned by the state to each taxing district based on the percentage of PGE property within each district. Each October, Oregon tax bills are received by PGE and paid by on or before November 15th in order to receive the 3% full-payment discount.

Q. Has PGE utilized property tax savings incentives for its major construction projects?

A. Yes, for Biglow Canyon PGE and Sherman County executed a Strategic Investment Program (SIP) property tax abatement, which is significantly reducing taxes for a 15-year period beginning in 2008. Also, PGE has completed negotiations with Columbia and Morrow counties and has executed SIP property tax abatement agreements, if PGE's energy and capacity benchmark bids go forward. For PGE's renewable energy benchmark project, PGE will inherit the benefits of the SIP agreement the owner had previously entered into with Gilliam County. For the Cascade Crossing transmission project, PGE is contemplating negotiating SIP property tax abatements as well. This will be complex, because that project spans a number of Oregon counties, each of which must approve the SIP.

Previously, PGE had negotiated a 5-year property tax holiday for its Port Westward plant built in 2007. The tax holiday period has expired and cannot be renewed.

Q. How does PGE estimate property taxes for ratemaking purposes?

A. As described above, property tax assessed value is determined using three approaches: 1) Cost, 2) Income and 3) Comparable Sales. Since the income and comparable sales methods involve complex estimates of future events, such as projected income, capitalization rates, growth and future stock values, PGE relies on the cost method to estimate property taxes for ratemaking purposes.

Q. Why does PGE rely on the Cost method for determining future years' assessed values?

A. PGE has found there is a strong correlation between net book value of utility plant and assessed value. For example, at January 1, 2012, Oregon assessed value was $3.4 billion. PGE net book value of utility plant (per 2011 FERC Form 1) was $3.6 billion. For Montana the correlation between assessed value and net book value of utility plant is not as strong due to that state's utilization of the WSATA formula and its assertion that the low book value of the Colstrip plant is not reflective of its real market value. PGE's assessed value of Montana property as of January 1, 2012 was $243 million. Net book value of Montana property as of that date was approximately $137 million.

Q. How is this prospective Cost valuation determined?

A. Starting with the latest actual assessed value for each state, PGE adds an estimate for projected capital expenditures. Because Oregon property taxes are assessed on a fiscal year basis, assessed values at January 1, 2013 and 2014 have to be calculated. Since Montana property taxes are assessed on a calendar year basis, the assessed value as of January 1, 2014 is only required.

Q. After estimated assessed value is calculated, what is the next step to determine 2014 property tax expense?

A. The next step is to estimate the average tax rate at which these values will be taxed. Rates may vary significantly depending on bond measures passed and other changes in each taxing district. For example, in Oregon for the fiscal year 2012/2013, county property tax rates range from less than 1% up to 2% of assessed value with a weighted average of 1.266%. For Montana, 2012 county property tax rates averaged approximately 2.098%. Multiplying projected assessed values by these average tax rates produces gross property tax expense.

Q. Are there any other material adjustments that need to be taken into account in determining property tax expense for ratemaking purposes?

A. Yes. Since some major projects have long construction periods, property taxes on these facilities need to be capitalized while they are CWIP. For the RFP benchmark projects, all property tax expense was capitalized for 2014 rather than included as operating expense. For all other projects, PGE used a historical-based capitalization rate of approximately 0.12%. This rate is lower than what might be expected because many standard or "blanket" jobs are not subject to property tax capitalization. Also, as previously mentioned, adjustments have to be made for the Biglow Canyon SIP agreement, which requires additional payments in lieu of property taxes paid to Sherman County.

Q. What is PGE's forecast for 2014 property taxes?

A. PGE's forecast of 2014 property taxes is $50.4 million, an increase of $8.7 million from 2011.

Q. What are the primary reasons why property taxes will increase from 2011 to 2014?

A. The estimated property tax expense increase from $41.7 million in 2011 to $50.4 million in 2014 is primarily due to the following factors: 1) $2 million increase due to the Port Westward Enterprise Zone tax abatement ending in 2012; 2) $4.3 million increase attributable to non-RFP construction projects being placed in service; and 3) $2.3 million increase related to additional bond measures passed by voters, tax rate variances between years, and other items.

VI. Capital Expenditures

Q. What are PGE's total 2014 capital expenditures?

A. As shown in PGE Exhibit 307 and summarized in Table 5 below, PGE forecasts \$970.4 million in total utility capital expenditures for 2014, compared with 2011 actual capital expenditures of \$301.9 million.

Table 5
(Capital Expenditures in \$millions)

Type:	2011 Actuals	2014 Test Year
Production	\$27.2	\$29.5
Transmission	\$3.8	\$2.0
Distribution	\$122.6	\$139.6
Intangible	\$6.9	\$11.2
General	\$30.9	\$37.0
CapEx - Operations	\$191.4	\$219.3
Strategic	\$110.5	\$176.1
RFPs	\$0.0	\$575.0
Total Capital Expenditures	\$301.9	\$970.4

Q. How does PGE account for capital expenditures?

A. As PGE spends capital for utility projects, we record it as CWIP, a non-rate base account. Once the project is completed, PGE moves the capital expenditures (and associated Allowance for Funds Used during Construction, or AFDC) from CWIP to plant-in-service accounts. Once moved to plant-in-service accounts, the project becomes part of PGE's rate base with associated depreciation expense and property tax expense recorded in the appropriate income statement accounts.

Q. Are there any significant capital expenditures that you do not expect will close to plant in service during 2014?

A. Yes. We forecast capital expenditures for the Cascade Crossing transmission project that we currently expect to close beyond 2014. In addition, we forecast capital expenditures for our proposed capacity, energy, and renewable projects in the RFPs that will also close beyond the test year. Our work papers detail the capital expenditures in 2013 and 2014 that are expected to close in 2014 (or prior) as well as those capital expenditures that are expected to close after 2014.

VII. Rate Base

Q. What is PGE's 2014 average rate base and what does it include?

A. The total 2014 average rate base is $3,126 million. PGE Exhibit 308 provides the details of the 2014 average rate base, which includes PGE's investment in plant in service, net of Accumulated Depreciation, Accumulated Deferred Taxes, and Accumulated Investment Tax Credits (ITC). In addition, the average rate base includes Fuel and Materials Inventory, Miscellaneous Deferred Debits and Credits, and Working Cash.

Q. How does PGE's 2014 rate base compare to rate base amounts approved (or pending) in prior dockets?

A. PGE Exhibit 309 shows that the average rate base approved/pending in prior dockets is $3,149 million. PGE's average rate base is nearly flat, decreasing by $23 million to $3,126 million.

Q. How did you develop the estimate of plant in service for the 2014 test year?

A. First, we estimated year-end 2012 embedded plant using actual results as of the end of the third quarter with forecasted closings through year-end. Next, we evaluated 2013 and 2014 capital additions. Certain larger projects were closed based on specific forecasted closing dates. For example, we forecast SO_2 controls at Boardman and PGE's investment the Readiness Center to close by December 31, 2013.

However, we model most capital additions by evaluating CWIP balances using historical experience. We then applied a forecast closing pattern to CWIP to develop plant-in-service estimates from 2013 and 2014 capital additions. Our work papers detail the development of 2014 plant-in-service from forecasted embedded plant at year-end 2014.

Q. Are there any new rate base items in 2014 relative to prior proceedings?

A. Yes. We have one new deferred debit balance in the 2014 test year. It is relatively small and is related to the Port Westward major maintenance accrual discussed earlier.

Q. Does PGE propose a new lead-lag study to update working cash in 2011?

A. Yes. PGE completed a new lead-lag study, a summary of which is provided as PGE Exhibit 310, and the study results are provided in our workpapers. The result is a working cash allowance factor of 3.98% for 2014 as compared to 3.90% used in UE 215.

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

A. Applying the 3.98% working cash factor to total forecasted operating expenses in 2014 of $1,517 million yields the working cash addition to rate base of $60.4 million, which is shown in PGE Exhibit 301.

Q. Does the lead-lag study take into account the cost of collateral deposits described in PGE Exhibit 1100?

A. No. With regard to purchased power and fuel, the lead-lag study evaluates the lag between delivery month of fuel or power and the payment of an invoice. It does not capture the financing costs associated with movements in the value of an energy/fuel position prior to the month of delivery, which is the basis of collateral requirements described in PGE Exhibit 1100.

VIII. Unbundling

Q. Have you unbundled the 2014 revenue requirement pursuant to OAR 860-038-0200?

A. Yes. PGE Exhibit 311 summarizes the results of unbundling the integrated revenue requirement, as required by OAR 860-038-0200, into the required functional areas or revenue requirement categories. Table 6 below summarizes the unbundled revenue requirement for 2014.

Table 6
(Unbundled Revenue Requirement - $millions)

Production	$1,077.6
Transmission	40.2
Distribution	547.0
Metering	3.8
Billing	60.0
Other Consumer Services	51.9
Ancillary Services	4.8
Public Purposes	Collected by separate tariff
Total	**$1,785.3**

The sum of the unbundled revenue requirement for these services equals the integrated revenue requirement as presented in PGE Exhibit 301.

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

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

Q. How did you unbundle PGE's 2014 expenses and Other Revenue?

A. We unbundled expenses and Other Revenue by analyzing each account within those categories. First, we determined which accounts could be directly assigned to one of the functional categories listed in Table 7 above. Second, we evaluated those accounts that could not be clearly assigned to determine a basis for allocation.

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

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

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

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

Q. How did you unbundle rate base?

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

Q. How did you unbundle other rate base?

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

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

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

IX. Qualifications

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

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

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

A. I received a Bachelor of Science degree in Business Administration with a finance emphasis from the University of Oregon and a Master of Business Administration degree from Portland State University. I have been employed at PGE since 2005, working in various departments including Corporate Finance, Investor Relations, and Utility Asset Management. I have worked in the Rates and Regulatory Affairs department since 2008.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
301	2014 Results of Operations Summary
302	Summary of Other Revenue Sources
303	Summary of Depreciation Expense by Plant Type
304	Summary of Amortization Expense
305	Summary of Income Taxes
306	Summary of Taxes Other Than Income
307C	Summary of Capital Expenditures
308	Summary of Rate Base
309	Reasons for Changes in Rate Base since UE 215 et. al.
310	Lead Lag Summary Results
311	Unbundled Results of Operations Summary

PGE Exhibit 301
2014 Results of Operations
Increase in Base Rates Needed for Reasonable Return
Dollars in (000s)

	2014 Results At 2011-13* Base Rates	Change for Reasonable Return	2014 Results After Change for Reasonable Return		
	(1)	(2)	(3)		
Operating Revenues					
Sales to Consumers (Rev. Req.)	1,682,745	102,529	1,785,274	6.1%	
Sales for Resale	-	-	-	104,790	incl. Sch. 145
Other Operating Revenues	21,396	-	21,396	1,787,535	6.2%
Total Operating Revenues	1,704,141	102,529	1,806,670		
Operation & Maintenance					
Net Variable Power Cost	639,194	-	639,194		
Operations O&M	227,957	-	227,957		
Support O&M	237,250	854	238,104		
Total Operation & Maintenance	1,104,402	854	1,105,255		
Depreciation & Amortization	275,026	-	275,026		
Other Taxes / Franchise Fee	108,106	2,564	110,670		
Income Taxes	30,424	39,484	69,908		
Total Oper. Expenses & Taxes	1,517,958	42,902	1,560,860		
Utility Operating Income	186,182	59,627	245,809		
Rate of Return	5.959%		7.863%		
Return on Equity	6.192%		10.000%		

* 2011-13 Rates per approved UE 215, UE-228, UE-249, UE-250

Average Rate Base			
Plant in Service	7,254,346	-	7,254,346
Accumulated Depreciation	(3,729,761)	-	(3,729,761)
Accumulated Def. Income Taxes	(506,558)	-	(506,558)
Accumulated Def. Inv. Tax Credit	4	-	4
Net Utility Plant	3,018,031	-	3,018,031
Misc Deferred Debits	46,932	-	46,932
Operating Materials & Fuel	73,324	-	73,324
Misc. Deferred Credits	(74,255)	-	(74,255)
Working Cash	60,415	1,707	62,122
Total Average Rate Base	3,124,446	1,707	3,126,153
Income Tax Calculations			
Book Revenues	1,704,141	102,529	1,806,670
Book Expenses	1,487,534	3,418	1,490,952
Interest Rate Base @ Weighted Cost of Debt	89,453	49	89,502
Production Deduction	-	-	-
Permanent Sch M Differences	(17,560)	-	(17,560)
Temporary Sch M Differences	21,363	-	21,363
State Taxable Income	123,351	99,062	222,413
State Income Tax	6,201	7,403	13,605
Federal Taxable Income	117,150	91,659	208,809
Fed Income Tax	15,708	32,081	47,789
Deferred Taxes	8,515	-	8,515
ITC Amort	-	-	-
Total Income Tax	30,424	39,484	69,908

PGE Exhibit 301
2014 Test Year
Capital Structure / Revenue Sensitive Costs
(000s)

Capital Structure:	Amount	Share	Cost	Weighted
Common Equity	N/A	50.00%	10.000%	5.000%
Preferred	N/A	0.00%	0.00%	0.000%
Long-Term Debt	N/A	50.00%	5.726%	2.863%
Total	N/A	100.00%		**7.863%**

Revenue Sensitive Costs:	
Revenues	1.000000
OPUC Fees	0.003125
Franchise Fees	0.025012
O&M Uncollectibles	0.005200
State Taxable Income	0.966663
State Tax @ 6.24%	0.072244
Federal Taxable Inc.	0.894419
Federal Tax @ 35%	0.313047
Total Income Taxes	**0.385291**
Total Rev. Sensitive Costs	**0.418627**
Utility Operating Income	0.581373
Net To Gross Factor	**1.720067**

RSC Gross-Up Factor 1.0345

State Income Tax:

	Appor	Rate	Weighted
Montana	3.27%	6.75%	0.221%
Washington	5.77%	0.00%	0.000%
California	1.74%	8.84%	0.154%
Oregon	94.02%	7.55%	7.098%
State			7.474%

Composite Tax Rate: **39.858%**

Check:	Fed Tax	35.00%
	State Tax	7.474%
	Tax Shield	-2.62%
	Composite	39.858%

PGE Exhibit 302
Other Revenue Detail
2010 - 2014 Test Year

Account	Description	2010 Actuals	2011 Actuals	2012 (9+3)	2013 Forecast	2014 Test Year
4560007	OthElecRev-TransmissionResale	$ (5,390,250)	$ (6,275,911)	$ (4,657,887)	$ (187,200)	$ -
4560008	OthElecRev-Gas for Resale	$ (405,903)	$ (276,006)	$ (435,309)	$ -	$ -
4560010	OthElecRev-TransmissionRevElim	$ -	$ (18,846)	$ (23,670)	$ -	$ -
4560011	Oil For Resale Revenue	$ -	$ (12,189)	$ -	$ -	$ -
Group 1: Power Cost Items - Not included in rev req		$ (5,796,153)	$ (6,582,951)	$ (5,116,866)	$ (187,200)	$ -
4470003	SalesfrResale-IntertiePGEtoPGE	$ (2,746,813)	$ (2,593,028)	$ (2,704,464)	$ (3,545,000)	$ (3,455,000)
5660002	TransOp-MiscExp-IntertieWhePGE	$ 2,746,813	$ 2,593,028	$ 2,704,464	$ 3,545,000	$ 3,455,000
Group 2: Intracompany transaction - PGE merchant purcha:		$ -	$ -	$ -	$ -	$ -
5660003	TransOp-MiscExpNonInterPGE-PGE	$ 43,418,531	$ 46,530,461	$ 46,893,443	$ 46,151,004	$ 46,151,000
5660004	TranOp-MiscExpNonIntRevPGE-PGE	$ (43,418,531)	$ (46,530,185)	$ (46,893,443)	$ (46,151,000)	$ (46,151,000)
Group 3: Intracompany transaction - PGE charging itself to \		$ -	$ 275	$ -	$ 4	$ -
5470001	OthGenOp-Fuel-PGE RevKBP Reser	$ (2,066,215)	$ (2,066,215)	$ (2,066,212)	$ (2,066,215)	$ (2,066,215)
5470002	OthGenOp-Fuel-KBP Month Reser	$ 2,066,215	$ 2,066,215	$ 2,066,217	$ 2,066,215	$ 2,066,215
Group 4: Intracompany transaction - PGE charging itself for		$ -	$ -	$ 5	$ (0)	$ -
4500001	Forefeited Discounts	$ (653,441)	$ (1,854,756)	$ (2,586,493)	$ (2,600,000)	$ (2,600,000)
4510001	Miscellaneous Service Revenues	$ (2,184,731)	$ (2,351,445)	$ (2,313,917)	$ (2,044,679)	$ (2,291,099)
4530001	Sales of Water & Water Power	$ 14,835	$ 17,839	$ (8,466)	$ -	$ -
4540001	Rent From Electric Property	$ (1,604,055)	$ (1,797,125)	$ (1,692,742)	$ (1,599,131)	$ (1,227,175)
4540002	RentFrElecProperty-Joint Pole	$ (5,366,933)	$ (4,966,741)	$ (5,324,950)	$ (5,286,465)	$ (5,286,465)
4560001	Other Electric Revenues	$ (8,418,028)	$ (3,057,172)	$ (3,602,300)	$ (2,704,345)	$ (2,547,345)
4560003	OthElecRev-FishWildlifeRecrOps	$ (12,557)	$ (17,976)	$ (8,888)	$ (16,314)	$ -
4560004	OthElecRev-SSHG	$ (346,613)	$ (387,946)	$ (328,073)	$ (222,611)	$ (88,317)
4560005	OthElecRev-Utility Non-Kwh	$ (99,844)	$ (34,396)	$ (30,180)	$ (60,000)	$ (60,000)
4560012	OthElecRev-Steam Sales	$ (1,747,435)	$ (1,695,644)	$ (1,094,536)	$ (1,614,954)	$ (1,614,954)
4561001	TransRevOthers-Non-Intertie	$ (1,695,964)	$ (1,565,735)	$ (1,806,023)	$ (1,798,892)	$ (1,311,342)
4561002	TransRevOthers-Intertie	$ (4,021,048)	$ (4,502,711)	$ (5,285,932)	$ (5,005,000)	$ (4,355,000)
5600003	TransOp-IntercoTransStudyRev	$ (15,585)	$ (151,992)	$ (5,091)	$ -	$ -
Group 5: Remainder		$ (26,151,397)	$ (22,365,801)	$ (24,087,590)	$ (22,952,390)	$ (21,381,697)
						$ (14,023) SunWay
						$ (21,395,720) Total

PGE Exhibit 303
Depreciation Detail ($000s)
2010 - 2014 Test Year

Property Group	2010 Actual	2011 Actual	2012 Actual	2013 Forecast	2014 Forecast	
Boardman	5,886	12,038	19,631	20,443	24,982	
Colstrip	6,728	4,800	4,906	4,748	5,262	
Beaver	9,003	3,766	3,573	3,622	3,914	
DSG	200	321	346	709	1,033	
Biglow Canyon	30,309	40,047	38,298	36,616	35,030	
Coyote Springs	5,953	4,221	5,052	4,854	4,689	
Port Westward	7,891	7,007	6,820	6,692	6,611	
Hydro	8,836	11,681	12,418	11,920	12,579	
Transmission	10,482	8,935	9,606	9,711	9,682	
Distribution	107,930	108,191	111,530	113,047	116,349	
General Plant	15,348	16,575	18,567	20,922	24,904	
Total	208,566	217,582	230,747	233,284	245,035	
					(2,176)	Remove Boardman Decomm
					(54)	Retail Adj.
					112	SunWay
					242,917	Total

2010 forecasted depreciation excludes coal car depreciation of 630 and vehicle depreciation of 5,309.

2011 Test year depreciation excludes coal car depreciation of 349 and vehicle depreciation of 5,526.
2011 Test year assumes a 2040 terminal date for Boardman
2011 Test year excludes effects of depreciation study settlement conferences.

2011 Boardman actual depreciation includes effects of the Schedule 145 Tariff, which incorporates the site specific decomissioning study and a shortened depreciable life from 2040 to 2020.
2011 actual depreciation excludes coal car depreciation of 268 and vehicle depreciation of 3,970.

2012 forecasted depreciation excludes coal car depreciation of 261 and vehicle depreciation of 3,822.

2013 forecasted depreciation excludes coal car depreciation of 261 and vehicle depreciation of 4,106.

2014 forecasted depreciation excludes coal car depreciation of 261 and vehicle depreciation of 4,214.

PGE Exhibit 304
Amortization Detail ($000s)
2010 - 2014 Test Year

Item	FERC Account	AWO	Actual 2010	Actual 2011	Forecast 2012	Budget 2013	Test Year 2014
Equity Issuance Fees -2009	4&&		650,000	671,800	671,800	671,800	
Equity Issuance Fees -2011	4&&			1,050,000	1,050,000	1,050,000	
Equity Issuance Fees -2014	4&&						1,315,900
Port Westward Major Maint. Accrual	4&&						4,946,816
Remove Boardman Decomm (to Sch. 145)	4&&						1,512,747
Def Tax Asset Amortization	4&&						237,796
Software Amort (Intangible)	404.0	4040001	12,752,445	13,178,424	17,305,027	18,537,077	18,603,446
Other Intangible Amort (includes Hydro Relicensing)	404.0	4040001	4,470,737	6,097,457	5,836,639	3,322,969	3,175,877
Boardman Decommissioning- UE215	407.3	3000000185		(431,270)	(462,960)	(490,598)	(490,598)
Colstrip Common FERC Adjustment	407.3	7000000107	322,140	322,140	322,140	322,140	322,140
AMI Project Office Costs	407.3	7000000129			1,382,835		
Gain on Asset Sales, UE115	407.3	7000000317	115,085				
Accumulated ARO Boardman	407.3	7000000236		(1,064,421)	(1,025,518)	(1,022,149)	(1,022,149)
Coyote Springs Major Maintenance	407.3	7000000322	2,044,272	2,044,272	2,044,272	2,044,272	4,411,753
ISFSI Tax Credits	407.3	7000000323	3,122,980	2,592,331	2,274,749		
Accelerated Depreciation- Old Meters	407.3	7000000351	(4,790,881)				
Intervener CUB Fund Amortization	407.3	7000000356		47,677			
Intervener Match Fund Amortization	407.3	7000000357		46,082			
Intervener Issue Fund Amortization	407.3	7000000358		125,547			
Intervenor CUB Fund 2	407.3	7000000888		152,457	12,574		
Intervenor Match Fund 2	407.3	7000000889		147,359	12,154		
Intervenor Issue Fund 2	407.3	7000000891		407,468	33,112		
Gain on Asset Sales, UE115	407.4	7000000317	15,687				
2011 Local 408/MCBIT Deferral	407.4	3000000135			(604,940)		
Interest Income PES Note	407.4	7000000319			(266,032)		
Coyote Springs Major Maintenance	407.4	7000000322	(2,683,748)	(3,737,959)	(3,886,965)		
Sunway 3	407.4	7000000727	(20,529)	(45,480)	(34,110)		
ISFSI Tax Credits- Used	407.4	7000000324		(18,096,269)	(110,290)		
SB 1149 Residual Balance	407.4	7000000335		(1,436,041)	(90,226)		
Regulatory Deferral (Capital Deferral)	407.4	7000010741			(15,622,661)	(19,996,594)	
Trojan Decommissioning	407.0	7000000045	4,646,000	3,500,278	3,500,175	3,500,000	3,500,000
Gain from Property Sales	411.6		(115,085)				
Independent Evaluator Deferral	407.3	7000000123				315,452	
FiT Pilot Program	407.3	7000002001			4,896,926	5,202,769	
Coyote Springs GE LTSA Exp	407.4	7000000673				(4,263,914)	(4,404,919)
Residual Account	407.3	7000001030			891,283		
Total Amortization			20,531,113	5,573,864	17,240,714	9,195,237	32,110,824
Excl. ISFSI Tax Credits			20,531,113	23,670,133	17,351,004	9,195,237	32,110,824

PGE Exhibit 305
Income Tax Summary
Reasons For Change (UE-215 et. al. 2012/13 Test Years vs. 2014 Test Year)
(000s)

Income Tax Expense	UE 215 et. al. 2012/13 Test Years	2014 Test Year
Book Revenues	1,676,576	1,806,670
Book Expenses (including Depreciation)	1,366,404	1,490,952
Interest Deduction	95,572	89,502
Book Taxable Income	214,601	226,216
Permanent Sch. M	(18,274)	(17,560)
Temporary Sch. M	133,967	21,363
Tax Taxable Income	98,908	222,413
Current State Taxes	6,188	16,622
State Tax Credits	(3,699)	(3,017)
Net State Income Tax	2,490	13,605
Federal Taxable Income	96,418	208,809
Current Federal Taxes	33,829	73,083
Federal Tax Credits	(31,137)	(25,294)
ITC Amortization	-	-
Deferred Taxes	52,076	8,515
Total Income Tax	57,257	69,908
Effective Tax Rate	26.68%	30.90%
Change in Taxes		12,651
Analysis of Tax Change:		
Effective Tax Rate Change		4.22%
Book Taxable Income (UE 215 et. al)		214,601
Increase in Taxes Due to Higher Effective Rate		9,061
Change in Book Taxable Income (2014 vs UE 215 et. al.)		11,615
2014 Effective Tax Rate		30.90%
Increase in Taxes Due to Higher Book Taxable Income		3,590
Sum of Tax Impacts		12,651

PGE Exhibit 306
Taxes Other Than Income
2010 - 2014 Test Year

Item	FERC Account	AWO	Actual 2010	Actual 2011	Forecast 2012	Budget 2013	Test Year 2014
Payroll Taxes	408.1	Note 1	12,070,057	12,572,279	13,251,450	13,023,523	14,075,601
Property Taxes - Oregon	408.1	4081001	33,183,881	37,765,568	40,716,730	41,717,622	44,936,843
Property Taxes - Washington	408.1	4081002	42,733	45,644	36,072	41,616	37,088
Property Taxes - Montana	408.1	4081003	3,869,903	3,907,047	4,454,040	4,017,696	5,405,817
Franchise Fees	408.1	4081010, 4081011	38,818,329	40,567,687	42,263,256	41,962,201	44,652,511
Foreign Insurance Excise Tax	408.1	4081012	9,200	-	9,600	-	-
Misc. Tax & Lic Fees - Oregon	408.1	4081013	1,194,209	1,342,211	1,378,133	1,200,522	1,444,452
Misc. Tax & Lic Fees - Montana	408.1	4081014	451,197	360,758	421,589	406,500	396,000
Total Taxes Other Than Income			89,639,509	96,561,192	102,530,869	102,369,680	110,948,312

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

Exhibit 307C

Confidential

PGE Exhibit 308
Average Rate Base (000s)
Test Year based on 12 months ending 12/31/14

		2014 Test Year
	Plant in Service	7,254,346
Less:	Accumulated Depreciation/Amortization	(3,729,761)
	Accumulated Deferred Taxes	(506,558)
	Accumulated Deferred ITC	4
Net Utility Plant		3,018,031
Operating Materials and Fuel Stocks		73,324
Deferred Debits		
	Sunway I - III	1,634
	Colstrip Common FERC Adj	903
	Glass Insulators	2,220
	Dispatchable Standby Generation	7,581
	UE 197 Generation Maintenance Deferral	3,080
	Equity Issuance Fees	12,645
	Major Maint. Accruals (Coyote & PW)	1,438
Deferred Credits		
	Injuries & Damages	(7,223)
	Customer Deposits	(12,018)
	Customer Advances	(10)
	Misc. Other	(37,574)
Working Capital		62,122
Average Rate Base		3,126,153

PGE Exhibit 309
Rate Base Comparison
UE 215 et al. vs. 2014 Test Year
(000s)

	UE 197 et al Test Years	Working Cash Requirements	Equity Issue Reg Asset	Coyote Maj. Maint. Accrual	Port Westward Major Maint. Accrual	Capital Deferral	Accum. Def. Taxes (bonus depr., etc.)	Misc. Other	2014 Test Year
Plant in Service	6,394,661					114,493		745,192	7,254,346
Accum. Depr/Amort	(3,018,964)					(26,813)		(683,984)	(3,729,761)
Accum. Deferred Taxes/ITC	(349,494)					1,034	(158,094)		(506,554)
Net Utility Plant	3,026,203	-	-	-	-			61,208	3,018,031
Other Rate Base	67,755		(2,419)	(3,918)	1,256			(16,674)	46,000
Working Cash	55,520	5,839	-	-	-	763		-	62,122
Average Rate Base	3,149,478	5,839	(2,419)	(3,918)	1,256			44,534	3,126,153

PGE Exhibit 310
Working Cash Study
(Revenue and Expenses based on 01/01/2011 through 12/31/2011 Actuals)

Revenues		Annual Revenue	Lag Days	Dollar Days
Sales to Consumers		1,691,418	41.1	69,600,092
Meter cycle	15.2 days			
Billing cycle	3.0 days			
Collection cycle	22.9 days			
Other revenues		(17,824)	11.2	(198,892)
Total Revenue		1,673,594	41.5	69,401,200

Expenses	Annual Expense	Lag Days	Dollar Days
Fuel			
Oil	313	28.7	8,989
Coal	112,229	14.9	1,671,458
Natural Gas	247,073	37.5	9,266,341
Total Fuel	359,615	30.4	10,946,788
Purchase Power	690,149	35.4	24,455,851
Labor			
Hourly Wages	83,895	16.4	1,375,883
Salary	119,198	16.0	1,907,163
Incentives	5,981	247.0	1,477,360
Total Labor	209,074	22.8	4,760,406
Misc O&M			
License Fees	50,432	3.3	168,703
Prepaid Insurance	8,436	(177.5)	(1,497,450)
Rent	4,973	(14.7)	(73,146)
Other Benefits	54,925	2.0	110,342
Total Misc O&M	118,766	(10.9)	(1,291,551)
Taxes			
Federal Income	2,500	5.6	14,099
State & Local Income (Ore.)	178	5.6	1,005
State Income (Mont.)	116	5.6	654
Property Tax (Ore.)	39,063	(41.8)	(1,631,722)
Property Tax (Mont.)	4,322	244.0	1,054,588
Property Tax (Wash.)	42	396.5	16,701
Unemployment (Ore.)	2,072	90.6	187,779
Unemployment (Fed.)	163	90.6	14,816
Tri-Met	1,242	90.6	112,502
FICA	17,403	16.2	281,322
Total Taxes	67,102	0.8	51,744
Total Expenses	1,444,706	26.9	38,923,238

Calculation of Working Cash Factor:	
Revenue Lag Days	41.5
Expense Lag Days	26.9
Excess Lag	14.5
WC Factor	3.98%

PGE Exhibit 311
Unbundled Results of Operations Summary
2014 Results at Reasonable Return
Dollars in $000s

	Production	Transmission	Distribution	Ancillary	Metering	Billing	Consumer	Total
Operating Revenues								
Sales to Consumers (Rev. Req.)	1,077,604	40,218	546,993	4,788	3,750	59,971	51,950	1,785,275
Sales for Resale	-	-	-	-	-	-	-	-
Other Operating Revenues	6,692	5,670	13,745	(4,788)	1	3	72	21,396
Total Operating Revenues	1,084,296	45,888	560,739	-	3,751	59,974	52,022	1,806,671
Operation & Maintenance								
Net Variable Power Cost	639,194	-	-	-	-	-	-	639,194
Total Fixed O&M	122,469	11,605	93,823	-	-	-	-	227,897
Other O&M	55,939	6,422	77,505	-	2,423	53,058	42,818	238,164
Total Operation & Maintenance	817,601	18,027	171,328	-	2,423	53,058	42,818	1,105,255
Depreciation & Amortization	109,515	8,752	143,176	-	2,738	5,387	5,458	275,026
Other Taxes / Franchise Fee	32,556	3,284	70,138	-	436	835	3,421	110,670
Income Taxes	8,955	4,971	55,883	-	(484)	377	207	69,909
Total Oper. Expenses & Taxes	968,627	35,035	440,526	-	5,112	59,657	51,905	1,560,861
Utility Operating Income	115,669	10,854	120,213	-	(1,361)	317	117	245,809
Rate of Return	7.86%	7.86%	7.86%	N/A	7.86%	7.86%	7.86%	7.86%
Return on Equity	10.00%	10.00%	10.00%	N/A	10.00%	10.00%	10.00%	10.00%
Average Rate Base								
Utility Plant in Service	3,456,400	294,953	3,355,177	-	65,014	32,726	50,076	7,254,346
Accumulated Depreciation	1,751,599	132,546	1,712,521	-	70,706	26,764	35,625	3,729,761
Accumulated Def. Income Taxes	341,463	26,751	114,288	-	10,559	3,694	9,803	506,558
Accumulated Def. Inv. Tax Credit	(0)	(0)	(4)	-	-	-	-	(4)
Net Utility Plant	1,363,338	135,656	1,528,372	-	(16,251)	2,268	4,648	3,018,031
Operating Materials & Fuel	63,489	334	9,501	-	-	-	-	73,324
Misc Deferred Debits	17,646	564	5,879	-	17	31	62	24,199
Misc. Deferred Credits	(11,966)	86	(32,442)	-	(1,278)	(638)	(5,285)	(51,522)
Working Cash	38,551	1,394	17,533	-	203	2,374	2,066	62,122
Total Average Rate Base	1,471,059	138,034	1,528,843	-	(17,308)	4,036	1,491	3,126,153

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 262

Net Variable Power Cost

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Mike Niman
Terri Peschka

February 15, 2013

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I. Introduction

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

A. My name is Mike Niman. My position at PGE is Manager, Financial Analysis.

My name is Terri Peschka. My position at PGE is General Manager, Power Operations. Our qualifications are included at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to provide the initial forecast of PGE's 2014 Net Variable Power Costs (NVPC). We discuss several of the updates to parameters from PGE's NVPC forecast for 2013, as well as modeling changes. We compare our initial 2014 forecast with PGE's final 2013 NVPC forecast and explain why the per-unit expected NVPC have decreased by approximately $0.87 per MWh.

Q. What is PGE's initial net variable power cost forecast?

A. Our initial 2014 NVPC forecast is $639.2 million, based on contracts and forward curves as of December 6, 2012. This initial 2014 NVPC forecast represents a reduction of approximately $11.9 million relative to our final 2013 NVPC forecast filed in the 2013 Annual Update Tariff (AUT) proceeding (Docket No. UE 250).

Q. Will PGE make a separate 2014 test year AUT filing?

A. No. The NVPC portion of this general rate case establishes the basis for recovering these costs and will be the 2014 forecast to which we compare the 2014 actual NVPC pursuant to the provisions of Schedule 126, which implements the Power Cost Adjustment Mechanism (PCAM).

Q. Are there Minimum Filing Requirements (MFRs) associated with PGE's NVPC filings?

A. Yes. Commission Order No. 08-505 adopted a list of MFRs for PGE in AUT filings and GRC proceedings. The MFRs define the documents PGE will provide in conjunction with the NVPC portion of PGE's initial (direct case) and update filings of its GRC and/or AUT proceedings. PGE Exhibit 401 contains the list of required documents as approved by Order No. 08-505. The required MFRs are included as part of our electronic work papers, with the remainder of the MFRs to be submitted within fifteen days of this filing (i.e. March 1, 2013). As with PGE's NVPC filings in the 2013 AUT, the MFR documents are designated as either "confidential" or "non-confidential".

Q. What schedule do you propose for NVPC updates in this docket?

A. We propose the following schedule for our power cost update filing:

- April 1 – Update parameters and forced outage rates; power, fuel, emissions control chemicals, transportation, transmission contracts, and related costs; gas and electric forward curves; planned thermal and hydro maintenance outages; wind resource energy forecasts; load forecast; and any errata corrections to our February 15 initial filing;
- July – Update power, fuel, emissions control chemicals, transportation, transmission contracts, and related costs; gas and electric forward curves; planned thermal and hydro maintenance outages; wind day-ahead forecast error cost; variable energy integration costs; and loads;
- September – Update power, fuel, emissions control chemicals, transportation, transmission contracts, and related costs; gas and electric forward curves; planned hydro maintenance outages; and loads; and

- November – Two update filings: 1) update gas and electric forward curves; final updates to power, fuel, emissions control chemicals, transportation, transmission contracts, and related costs; long-term opt-outs; and 2) final update of gas and electric forward curves.

Q. How is the remainder of your testimony organized?

A. After this introduction, we have six sections:

- Section II: MONET Model;
- Section III: MONET Updates and Modeling Changes;
- Section IV: Comparison with 2013 NVPC Forecast;
- Section V: Qualifications.

II. MONET Model

Q. How did PGE forecast its NVPC for 2014?

A. As in prior dockets, we used our power cost forecasting model, called "MONET" (the Multi-area Optimization Network Energy Transaction model).

Q. Please briefly describe MONET.

A. We built this model in the mid-1990s and have since incorporated several refinements. In brief, MONET models the hourly dispatch of our generating units. Using data inputs, such as forecasted load and forward electric and gas curves, the model minimizes power costs by economically dispatching plants and making market purchases and sales. To do this, the model employs the following data inputs:

- Forecasted retail loads, on an hourly basis;
- Physical and financial contract and market fuel (coal, natural gas, and oil) commodity and transportation costs;
- Thermal plants, with forced outage rates and scheduled maintenance outage days, maximum operating capabilities, heat rates, operating constraints, and any variable operating and maintenance costs (although not part of net variable power costs for ratemaking purposes, except as discussed below);
- Hydroelectric plants, with output reflecting current non-power operating constraints (such as fish issues) and peak, annual, seasonal, and hourly maximum usage capabilities;
- Wind power plants, with peak capacities, annual capacity factors, and monthly and hourly shaping factors;
- Transmission (wheeling) costs;
- Physical and financial electric contract purchases and sales; and

- Forward market curves for gas and electric power purchases and sales.

Using these data inputs, MONET simulates the dispatch of PGE resources to meet customer loads based on the principle of economic dispatch. Generally, any plant is dispatched when it is available and its dispatch cost is below the market electric price. Thermal plants can also be operating in one of various stages – maximum availability, ramping up to its maximum availability, starting up, shutting down, or off-line. Given thermal output, expected hydro and wind generation, and contract purchases and sales, MONET fills any resulting gap between total resource output and PGE's retail load with hypothetical market purchases (or sales) priced at the forward market price curve. In Section III below we discuss enhancements to PGE's MONET power cost model.

Q. How does PGE define NVPC?

A. NVPC include wholesale (physical and financial) power purchases and sales ("purchased power" and "sales for resale"), fuel costs, and other costs that generally change as power output changes. PGE records its net variable power costs to Federal Energy Regulatory Commission (FERC) accounts 447, 501, 547, 555, and 565. Based on prior Commission decisions, we include some fixed power costs, such as excise taxes and transportation charges, because they relate to fuel used to produce electricity. For purposes of FERC accounting, these costs are recorded in a balance sheet account as inventory (FERC 151); this inventory is then expensed as the fuel is consumed. We include certain variable chemical costs in this filing, and discuss this in more detail below. We exclude some variable power costs, such as certain variable operation and maintenance costs (O&M), because they are already included elsewhere in PGE's accounting. However, variable O&M is used to determine the economic dispatch of our thermal plants. The "net" in NVPC refers to net of forecasted wholesale sales of electricity, natural gas, fuel and associated financial instruments.

Q. Do the MFRs provide more detailed information regarding the inputs to MONET?

A. Yes. The MFRs provide detailed work papers supporting the inputs used to develop this initial forecast of 2014 NVPC.

III. MONET Updates and Modeling Changes

Q. Does PGE present both parameter updates and modeling changes in this initial filing?

A. Yes. Because this is a GRC proceeding, we include not only the parameter revisions allowed under PGE's AUT (Tariff Schedule 125), but also model changes and updates.

Q. What load forecast do you use in this initial filing?

A. We use the 2014 retail load forecast described in PGE Exhibit 1300. That forecast is approximately 19,106,397 MWh, or 2,181 MWa, an increase of 16 MWa from the 2013 test year forecast presented in PGE's most recent AUT in Docket No. UE 250.

Q. What updates and model changes do you propose in this docket?

A. In this initial filing we include many of the updates typically included in an April 1 AUT filing. Additional items requiring 2012 data, or for which updated data were not available in a timely manner for this filing, will also be updated in our April 1 filing. Among those items is the update to the thermal forced outage rates. We plan to file an update that includes forced outages rates based on 2009–2012 data by April 1, 2013, consistent with information that would be used in an initial AUT filing for 2014. By that date, we will have processed the 2012 data needed to complete the outage rate calculations. For this filing, we use the same forced outage rates based on 2008–2011 data from UE 250 (2013 AUT). We will continue to update several of the items included under Schedule 125 as this docket proceeds.

We include the following updates and modeling changes in our initial MONET runs:

1. Wind energy forecasts move to five-year rolling average;
2. Coal plants now use MONET's dynamic programming dispatch model, consistent with the dispatch model used for gas-fired resources;

3. Dynamic programming dispatch model now models variable O&M using monthly values;
4. MONET's modeling of ancillary services has been updated;
5. The latest Pacific Northwest Coordination Agreement (PNCA) Headwater Benefits study is now included in our hydro data;
6. The following emissions control chemicals in use at PGE's plants are now included in NVPC rather than O&M for ratemaking purposes:
   - Mercury and sulfur dioxide control chemicals at the Boardman plant;
   - Sulfur dioxide control chemicals at the Colstrip Unit 3 and Unit 4 plants;
   - Nitrogen oxide control chemicals at the Port Westward and Coyote Springs plants;
7. The biomass test burn at the Boardman plant is scheduled for the second quarter of 2014; and,
8. The cost estimate of wind day-ahead forecast error based on PGE's wind integration study will be included as an update in the July filing.

Q. What is the net effect on PGE's initial 2014 NVPC forecast of these updates and modeling changes?

A. The net effect of these updates and modeling changes is a $9.8 million increase in PGE's initial 2014 NVPC forecast. The updates related to emissions control chemicals simply move the chemical costs from PGE's O&M budgets into the NVPC forecast, and, therefore, do not represent an increase in the overall amount that PGE would otherwise be seeking to recover in this proceeding. Excluding these chemical costs, the updates and modeling changes described below result in a $4.7 million increase in PGE's initial 2014 NVPC forecast. We discuss the regulatory treatment of these emissions control chemical costs in more detail below.

A. Wind Energy Forecast

1. Biglow Canyon

Q. How was PGE's forecast of Biglow Canyon wind energy developed in recent AUT and GRC proceedings?

A. The Biglow Canyon wind energy forecast previously relied on annual and monthly capacity factors based on a study completed in 2005 for PGE by Garrad Hassan America (GH).

Q. Did PGE have actual experience with the generation from Biglow Canyon at the time the 2005 study was prepared by GH?

A. No. Biglow Canyon Phase I was placed into service in 2007. Biglow Canyon Phase II was placed into service in 2009. Biglow Canyon Phase III was placed into service in 2010. The values provided in the 2005 GH study were based on the best information and techniques available at that time.

Q. Please explain the method used by PGE in this proceeding for forecasting Biglow Canyon energy.

A. The Biglow Canyon energy forecast used in this filing is based on a five-year average using PGE's actual generation history at the facility, coupled with the energy forecast previously used in MONET as established in the UE 215 proceeding (2011 GRC). For this initial filing, full-year actual generation data for each Phase of Biglow Canyon through year-end 2011 are used. The previous MONET energy forecast is then used for the remaining years in order to calculate a five-year average for the entire plant for the 2008–2012 period.

PGE's April 1 update filing in this proceeding will incorporate actual generation data through year-end 2012 into the five-year average.

Q. How will PGE include the most recently available actual Biglow Canyon generation data in the NVPC forecast each year?

A. PGE will update the Biglow Canyon energy forecast to incorporate the most recent year's actual generation data, and include this forecast in the AUT or GRC NVPC forecast, by April 1 each year. The Biglow Canyon energy forecast will be based on a five-year rolling average and will continue to rely on the previous MONET energy forecast where necessary.

Q. Why is this new method based on historical actual generation at Biglow Canyon better than the method used previously?

A. A forecast based on actuals is fair, transparent, reflects changing operational experiences, incorporates the effects of recent environmental conditions, is not tied solely to outdated forecasting techniques, and is consistent with other aspects of PGE's power cost forecast where actuals serve as the basis for the forecasted value (e.g., thermal forced outage rates, generation under certain wind PPAs (Klondike II), and the BPA imbalance premium). The method we propose allows for a smooth transition from the values previously used in MONET to a forecast based on PGE's actual experience.

Q. What effect does the updated Biglow Canyon energy forecast have on PGE's initial 2014 NVPC forecast?

A. The updated Biglow Canyon energy forecast increases PGE's initial 2014 NVPC forecast by approximately $2.7 million.

2. Vansycle Ridge

Q. How was PGE's forecast of the Vansycle Ridge contract wind energy developed in recent AUT and GRC proceedings?

A. The energy forecast for the Vansycle Ridge contract was previously determined based on the average of actual generation over the lifetime of the plant.

Q. How does PGE forecast the wind energy for the Vansycle Ridge contract in this proceeding?

A. In this proceeding, the wind energy forecast for the Vansycle Ridge contract is calculated as an average of the most recently available five years of actual generation. For this initial filing, the five-year average is for the period 2007-2011. In the April filing, the five-year average will be updated to include 2012 data.

Q. Why is PGE using a five-year average for the Vansycle Ridge contract energy forecast?

A. Several factors support PGE's move to a five-year rolling average for the Vansycle Ridge contract energy forecast in this proceeding. The use of a five-year average is consistent with the method proposed for Biglow Canyon. As discussed with respect to Biglow Canyon, the five-year average will reflect the changing operational experiences with the plant, as well as the effects of recent environmental conditions. The use of a five-year average is also consistent with the method that has been used to forecast the energy for the Klondike II wind contract.

Q. What effect does the updated Vansycle Ridge contract energy forecast have on PGE's initial 2014 NVPC forecast?

A. The updated Vansycle Ridge contract energy forecast increases PGE's initial 2014 NVPC forecast by approximately $0.05 million.

B. Coal Plants Switch to Dynamic Programming Dispatch Model

Q. Please provide a brief explanation of the coal plant dispatch model used in recent AUT and GRC NVPC proceedings.

A. Historically, coal plants have been dispatched in MONET by the "non-cycling logic". The non-cycling logic was part of the original MONET design from 1996 and was intended to be a simple and quick approach to modeling unit commitment.

Q. Why does PGE propose to change the coal plant dispatch model in this initial filing?

A. The original non-cycling logic was adequate during periods when the plants were generally "deep in-the-money," and provided for very fast model execution. However, now that the plants dispatch down more frequently in MONET, the model results using the original dispatch logic are becoming less realistic. The dynamic programming dispatch optimization logic currently used in MONET for the combined-cycle combustion turbine plants is much more robust and accurate.

Q. Please explain the enhanced coal plant dispatch model used for this initial filing?

A. For this initial filing, PGE has switched the coal-fired dispatch model from the original non-cycling logic to the existing dynamic programming model. The dynamic programming model achieves dispatch decisions that maximize the plants' value in each period, while accurately incorporating operational constraints. Information regarding the gas-fired plant dispatch model has been provided by PGE in the MFR documents accompanying recent AUT filings, and additional detail will be provided in our work papers and with the MFRs for this filing.

Q. Please briefly describe dynamic programming.

A. Dynamic programming (DP) is a computational approach to multi-stage decision problems. The "stages" in the current problem are the hours for which a decision must be made to dispatch or not dispatch the plant. The DP logic provides the ability to look ahead over the year and optimize the dispatch across all stages by maximizing a "payout" function, subject to plant constraints. This logic is very robust and, for the given inputs, produces an optimal, least-cost dispatch. In-depth discussions of dynamic programming and this specific dispatch model are provided in our work papers and in the MFRs.

Q. How does the DP approach maximize plant value?

A. The objective function of the DP algorithm is to maximize the payoff function for the year. The payoff is calculated as wholesale market revenues, less variable fuel and variable O&M costs. To realistically represent the dispatch decision-making process, the algorithm must consider interdependencies across hours of plant operation; the decision to operate cannot be made on an hour-by-hour basis. The payoff must be maximized over the entire dispatch cycle. To do this, the algorithm must be capable of "looking ahead." The DP model is a "perfect foresight" model; the model takes hourly electricity prices, fuel prices, and variable O&M costs as given and known in advance for the entire year. The algorithm results in the optimal decision; there is no other collection of dispatch sequences that will result in a higher overall payoff for the year.

Q. How does this more accurately reflect plant operational constraints?

A. The DP dispatch algorithm more closely mirrors actual plant operations than the previous dispatch model. The new method takes account of ramp-up and ramp-down constraints, minimum commitment times, start-up costs, and varying heat rates.

Q. Does this enhanced dispatch model affect PGE's initial 2014 NVPC forecast?

A. Yes. Implementing the enhanced coal plant dispatch model reduces PGE's initial 2014 NVPC forecast by $1.0 million.

C. Monthly Variable O&M for Dynamic Programming

Q. What is this enhancement?

A. This enhancement improves the DP logic by allowing for the use of monthly variable O&M values by plant, rather than a one-time study input.

Q. Why did PGE implement this enhancement?

A. Previously, the DP logic used plant variable O&M values that varied with operating state, but were static both across a given year and from one year to the next. Most other input parameters in MONET (such as plant heat rates and capacities) are specified on a monthly basis. The ability to vary plants' variable O&M values by month, rather than use a single study value, results in a more accurate representation of plant operations for the dispatch model, is consistent within MONET, and makes the modeling more flexible.

Q. Does this change affect PGE's initial 2014 NVPC forecast?

A. No. The monthly variable O&M values in the dispatch model for this initial filing are the same as the one-time study values used in the 2013 AUT, so this enhancement has no effect on PGE's initial 2014 NVPC forecast. In our April filing, however, we will update these monthly variable O&M values.

D. Ancillary Services Modeling (Dynamic Capacity)

Q. Please explain the method previously used in MONET to model ancillary services.

A. The provision for ancillary services (load following, regulation, spinning reserves, and non-spinning reserves) was previously addressed in MONET by certain hydro resources. In general, non-spinning reserves were implicitly covered by PGE's Eastside hydro resources, Pelton and Round Butte. Load following, regulation, and spinning reserves were modeled using PGE's Mid-Columbia (Mid-C) resources. Available generation on the Mid-C resources was first allocated to provide the needed ancillary services and the remaining generation was then allocated across the hours in a given month in order to maximize its value. This treatment was first implemented in MONET for the 2005 test year with the introduction of the Mid-C hourly dispatch logic.

Q. Why is a change to the modeling of ancillary services in MONET necessary?

A. A number of operational changes have occurred since the implementation of the Mid-C hourly dispatch logic, most notably, PGE's shares of several Mid-C resources decreased significantly and new generating resources were added to PGE's portfolio. Other issues arising from the old logic were also identified, including the absence of explicit modeling of non-spinning reserves, the inability to track ancillary service needs that remained unmet after the Mid-C dispatch, the inability to model self-integration of wind resources, and the lack of a means by which to model changing WECC operating reserve requirements. Our updated method models ancillary service obligations and capabilities of generating plants, contract resources, wind generation, dispatchable standby generation, and loads.

Q. Please explain the updated method for modeling dynamic capacity in MONET.

A. This enhancement replaces the existing Mid-C hourly dispatch logic with a new methodology. This new Mid-C dispatch includes updated operating constraints for the Mid-C projects, accounts for the implicit ancillary service abilities of PGE's Pelton and Round Butte hydro facilities and contracts, and improves the logic used to allocate ancillary services while optimizing Mid-C generation. This enhancement also includes new functionality that re-dispatches (after the economic dispatch occurs) eligible thermal plants in order to cover ancillary service needs that are unmet by the Mid-C resources for a given hour. Ancillary service needs that remain unmet at this point are assumed to be satisfied by spilling water, which allows for the provision of additional dynamic capacity by reducing hydro generation. In order to provide operating reserves, a plant needs to have the operational ability to operate in the requested manner. It is not simply a matter of adding a plant to the model, but requires ensuring that the necessary system controls, and communications and operational capabilities exist.

Q. What is PGE's goal in implementing this enhancement?

A. The goal is to improve MONET's modeling of hourly hydro generation and ancillary services, including the role of thermal plants and contracts with regard to ancillary services. Additionally, this enhancement provides greater flexibility to address future developments, such as updated reserve requirements and the integration of wind generation. In general, the goal is to more effectively model the role of dynamic capacity on PGE's system.

Q. How does this enhancement more accurately model PGE's resources and ancillary services requirements?

A. This enhancement models PGE's resources and ancillary services needs more accurately and effectively in a number of ways. First, the enhancement results in more accurate dispatch of PGE's Mid-C resources, which reduces PGE's initial 2014 NVPC forecast. Second, ancillary services needs that cannot be provided by PGE's hydro resources will now be allocated to PGE's thermal resources. This reallocation increases the NVPC forecast, but provides a more accurate representation of the uses of PGE's thermal plants. Overall, this modeling enhancement results in a more comprehensive and accurate representation of the uses of our resources for dynamic capacity purposes, which more accurately represents the operational dispatch of our generating plants and the resulting NVPC.

Q. What effect does this enhancement have on PGE's initial 2014 NVPC forecast?

A. The dynamic capacity enhancement reduces PGE's initial 2014 NVPC forecast by approximately $1.9 million.

Q. Will PGE integrate this enhancement into MONET for the April 1 update filing?

A. Yes. For this initial filing, the functionality of the dynamic capacity enhancement exists external from MONET. While modestly increasing the processing time, presenting this enhancement outside of MONET for this initial filing allows the analyst to isolate the effects of dynamic capacity on PGE's system and on the initial 2014 NVPC forecast. In the April 1 filing, this enhancement will be fully-integrated into MONET.

E. Pacific Northwest Coordination Agreement Study Update

Q. Please describe the update to include the new Pacific Northwest Coordination Agreement (PNCA) study.

A. Under the PNCA, the Northwest Power Pool conducts a 70-year regulation study called the Headwater Benefits Study (Study), based on a regulation model whose objective function is to maximize the firm energy load-carrying capability of the Northwest system as a whole. This model considers the loads and thermal resources of regional entities, as well as hydro resources. The model produces a simulated regulation of 70 water years under historical stream flows, which we then use, with a set of adjustments, to develop the average hydro energy inputs to MONET. For this filing, we updated from the 2008–2009 Study to the 2011–2012 Study to establish base average expected outputs for our hydro resources. We then adjusted these base figures using essentially the same adjustment steps used to develop hydro inputs to MONET in prior filings (such as removing PGE hydro maintenance, changing to continuous mode, and adjusting for end-of-study reservoir content).

Q. What effect does the PNCA-related change have on PGE's initial 2014 NVPC forecast?

A. Updating the PNCA study results in NVPC reduction of approximately $0.4 million.

F. Emissions Control Chemicals

Q. Why is it appropriate for PGE to include the costs associated with emissions control chemicals in its NVPC forecast?

A. It is appropriate for these costs to be reviewed in the context of PGE's NVPC because they are directly related to the operation of the respective plants. The forecast of plant operations that is relied upon by PGE to determine its 2014 NVPC forecast will be reviewed by parties to this proceeding. As such, it makes sense for the emissions control chemicals that are directly dependent upon these factors to be reviewed at the same time.

Q. Should these costs be treated in a manner similar to variable O&M?

A. No. O&M is established in a GRC and recovered in base rates. The variable portion of the plants' O&M is included in MONET for dispatch purposes. There is, however, a direct relationship between the plant generation forecast and the expected costs associated with these emissions control chemicals. The best method for forecasting the total chemical cost must rely on the cost driver forecasts, which are included in PGE's NVPC forecast as developed in MONET.

Q. How do these costs differ from variable O&M?

A. These emissions control chemical costs differ because there is no ambiguity as to their causation; there is a direct correlation between the costs incurred to achieve a particular emission target and the quantity and type of fuel used. Given that the quantities and types of fuel expected to be used during 2014 are modeled directly in MONET, the resulting total chemical costs are the best estimates.

Q. What chemicals does PGE move from O&M to NVPC for this initial filing?

A. We move the following chemicals from O&M to NVPC for this initial filing:

1. Activated carbon and calcium bromide for Mercury control at the Boardman plant;
2. Trona for sulfur dioxide control at the Boardman plant;
3. High-calcium lime for sulfur dioxide control at the Colstrip Unit 3 and Unit 4 plants;
4. Ammonia for nitrogen oxide control at the Coyote Springs plant; and
5. Ammonia for nitrogen oxide control at the Port Westward plant.

Q. Are the costs of any of these chemicals included in any other portion of PGE's filing in this docket?

A. No. The costs of these chemicals have been removed from the O&M values presented in PGE Exhibit 300 and are included only in PGE's 2014 NVPC forecast. While their inclusion in NVPC does increase PGE's 2014 NVPC forecast, it does not represent a net increase to PGE's request in this case.

1. Boardman – Mercury control chemicals

Q. Please explain the chemicals included for mercury emission control at Boardman.

A. Activated carbon and calcium bromide are used at Boardman to reduce mercury emissions from the plant. PGE began using the chemicals in 2011 in order to assure that the plant could comply with the Oregon Utility Mercury Rule.

Q. Please discuss the regulatory treatment of these mercury control chemical costs.

A. Costs incurred by PGE in 2011 and 2012 (treatment of 2013 expenses is expected to be consistent) related to these mercury control chemicals are subject to deferred accounting pursuant to the Orders in Docket Nos. UE 215 (PGE's 2011 test year GRC, Order No. 10-478) and UM 1513 (PGE's application for deferred accounting related to four capital projects, Order Nos. 11-153 and 12-050).

Q. What effect do these chemicals have on PGE's initial 2014 NVPC forecast?

A. The inclusion of the costs associated with these mercury control chemicals in NVPC increases PGE's initial 2014 NVPC forecast by approximately $1.2 million.

2. Boardman – Sulfur dioxide control chemicals

Q. Please explain the chemicals included for sulfur dioxide emission control at Boardman.

A. Trona will be used at Boardman as part of a dry sorbent injection (DSI) system to reduce sulfur dioxide emissions from the plant. Beginning July 1, 2014, the Regional Haze Rules established by the Oregon Department of Environmental Quality ("DEQ") mandate a maximum level of sulfur dioxide emissions that must be achieved at Boardman. The DSI system is being installed to help achieve compliance with those DEQ requirements, and is currently scheduled to be operational in the second-half of 2013 to allow for testing and system optimization prior to the required compliance date. PGE plans for this testing and optimization to occur during 2013 and the first-half of 2014.

Q. What effect do these chemicals have on PGE's initial 2014 NVPC forecast?

A. The inclusion of the costs associated with these sulfur dioxide control chemicals in NVPC increases PGE's initial 2014 NVPC forecast by approximately $1.9 million.

3. Colstrip – Sulfur dioxide control chemicals

Q. Please explain the chemicals included for sulfur dioxide emission control at Colstrip.

A. High-calcium lime is used at Colstrip Unit 3 and Unit 4 to reduce sulfur dioxide emissions to levels that comply with state and federal requirements.

Q. What effect do these chemicals have on PGE's initial 2014 NVPC forecast?

A. The inclusion of the costs associated with these sulfur dioxide control chemicals increases PGE's initial 2014 NVPC forecast by approximately $1.5 million.

4. Coyote Springs – Nitrogen Oxide Control Chemicals

Q. Please explain the chemicals included for nitrogen oxide emission control at Coyote Springs.

A. Coyote Springs uses anhydrous ammonia injected into the Heat Recovery Steam Generator to reduce nitrogen oxide emissions to levels that are compliant with State and Federal requirements.

Q. What effect do these chemicals have on PGE's initial 2014 NVPC forecast?

A. The inclusion of the costs associated with these nitrogen oxide control chemicals increases PGE's initial 2014 NVPC forecast by approximately $0.1 million.

5. Port Westward – Nitrogen oxide control chemicals

Q. Please explain the chemicals included for nitrogen oxide emission control at Port Westward.

A. Port Westward uses aqueous ammonia injected into the Heat Recovery Steam Generator to reduce nitrogen oxide emissions to levels that are compliant with State and Federal requirements.

Q. What effect do these chemicals have on PGE's initial 2014 NVPC forecast?

A. The inclusion of the costs associated with these nitrogen oxide control chemicals increases PGE's initial 2014 NVPC forecast by approximately $0.5 million.

G. Boardman Biomass Test Burn

Q. Please provide an overall description of the Boardman Biomass Project.

A. On April 9, 2010, PGE filed an Addendum to its 2009 IRP that included a revised operating plan for the Boardman power plant. OPUC Order No. 10-457 acknowledged PGE's 2009 IRP Addendum, which included the acknowledgement of PGE's BART III option. Per PGE's BART III option, coal-fired operations at Boardman will cease at the end of 2020. PGE is currently researching the possible substitution of torrefied biomass for coal as the fuel source for the Boardman plant. Since 2011, PGE has been growing and harvesting Arundo donax; a high-yield biomass crop being considered as a potential source of locally-accessible biomass to fuel the Boardman facility. In January 2013, PGE contracted with a vendor to develop design, fabricate, install, commission, and lease a torrefier at the Boardman plant to torrefy PGE's harvested green biomass as well as additional green biomass potentially procured from around the Boardman area. In 2014, PGE expects to perform a test burn using torrefied biomass as fuel. This test will provide data on plant operations, emissions, ash characteristics, and information regarding the effect on existing plant components of the biomass fuel. Boardman powered by biomass after the cessation of coal-fired operations could provide up to 300 MWa of renewable baseload energy (100% power for six months of the year) as well as help PGE meet the renewable portfolio standard of 25% of load by 2025.

Q. What is torrefaction?

A. Torrefaction is a form of pyrolysis where a biomass material is "roasted" in the temperature range of 200 to 350 degrees Celsius in a low oxygen atmosphere. The roasting yields a charred material that will not absorb water and can be stockpiled outdoors in large quantities for long periods of time.

Q. Who is supplying the additional green biomass for the test burn?

A. PGE will purchase additional biomass from around the Boardman area to supplement the Arundo. This additional biomass could include corn stover, wheat straw, and other varieties currently available near Boardman. PGE is also exploring purchasing torrefied briquettes from Canada to supplement the test burn.

Q. What are PGE's expected costs associated with the Boardman Biomass test burn?

A. PGE expects for the biomass used to fuel the test burn to cost approximately $6.0 million, consisting of the following components:

- $1.0 million for the procurement, farming, and harvesting of Arundo donax;
- $2.0 million for the procurement of other biomass sources;
- $2.4 million for acquiring, developing and running a torrefaction unit; and
- $0.60 million for other expected costs.

Q. How does PGE propose to incorporate the Boardman biomass test burn costs into the 2014 test year?

A. The costs associated with the Boardman biomass test burn are included in PGE's net variable power cost forecast for the 2014 test year. This treatment is consistent with Staff's Report in UM 1571 provided in OPUC Order No. 12-141. While opposing PGE's request for the specific accounting order sought in that proceeding, the Staff Report documents the agreement between Staff, PGE, and other parties that torrefied biomass would be, "treated as fuel and run through the Company's AUT" (Order No. 12-141, Appendix A, page 2). The torrefied biomass is a fuel source being burned at Boardman, and will be accounted for as fuel when burned. This fuel expense is directly aligned with the mechanics of the AUT and the PCAM.

Q. What effect does the biomass test burn have on PGE's initial 2014 NVPC forecast?

A. The Boardman biomass test burn increases PGE's initial 2014 NVPC forecast by approximately $5.2 million.

H. Wind Day-Ahead Forecast Error Cost

Q. Please briefly explain the cost of day-ahead forecast error, with respect to wind integration.

A. The cost of day-ahead forecast error is the cost incurred to re-optimize PGE's portfolio in order to account for the difference between the day-ahead and the hour-ahead forecast for wind generation. These costs materialize in the form of market transactions (purchases and sales) and the re-dispatch of available generation resources.

Q. Has an estimate of the cost of day-ahead forecast error been included in PGE's recent power cost proceedings?

A. Yes. An estimate related to the cost of wind integration has been included in the NVPC forecast by PGE since the 2008 test year in Docket No. UE 188. PGE has included the same estimate of this specific cost when developing the final NVPC forecast in each year since the 2009 test year in Docket No. UE 198. In the 2013 AUT (Docket No. UE 250), PGE proposed to update this estimate based on its Wind Integration Study.

Q. What estimate of the cost of day-ahead forecast error does PGE include in this initial 2014 NVPC forecast?

A. In this initial filing, PGE uses the same day-ahead forecast error cost that was used in PGE's final power cost update filing for 2013 in Docket No. UE 250.

Q. Does PGE plan to update this cost estimate for 2014?

A. Yes. The 2013 value will be used for the initial filings in this docket; however, PGE plans to provide an update in the July filing pursuant to the schedule proposed above. It is unlikely for an update to be available prior to that time given the need for consistency with the plant parameters modeled in MONET, which will be presented in our April 1 update filing, and the time- and labor-intensive nature of running PGE's wind integration model.

I. Forthcoming Updates

Q. Are there other items that PGE expects will require updates?

A. PGE currently expects to update several specific items during this proceeding in addition to the general updates listed in Section I above. These items include:

1. The ongoing Bonneville Power Administration (BPA) rate proceeding;
2. PGE's analysis regarding self-integration of variable energy resources;
3. A potential new WECC operating reserve standard; and
4. Potential fuel transport and capacity resource contract updates.

Q. Please discuss the ongoing BPA rate proceeding.

A. BPA is currently holding a rate proceeding to establish power and transmission rates effective October 1, 2013 (2014 fiscal year). The schedule in that proceeding indicates that a Draft Record of Decision will be filed June 13, 2013, and the Final Record of Decision will be filed on July 22, 2013. Our initial filing in this docket includes a portion of the rate increase proposed by BPA for the relevant service.

Q. What is the status of PGE's decision to self-integrate variable energy resources?

A. PGE is currently analyzing the most cost-effective approach to integrate our variable energy resources and will determine whether or not to enter into a contract with BPA for integration services by April 1, 2013, for the period of October 2013 through September 2015. If PGE determines that it will self-integrate the resources, rather than enter into an agreement with BPA, the integration requirements will be updated in the July filing.

Q. Please describe this potential new WECC operating reserve standard.

A. WECC Standard BAL-002-WECC-2 (WECC Bal-002) changes the calculation of operating reserves from 5% of hydro and wind generation, and 7% of thermal generation; to 3% of all generation, plus 3% of control area load.

Q. What is the status of approval of this new standard?

A. WECC-Bal-002 was initially approved by NERC in 2008. The standard was remanded in 2010 by FERC and has undergone revisions since that time. The NERC Board of Trustees adopted the revised standard in November 2012. It is currently awaiting final approval by FERC.

Q. What effect does this new standard have on PGE's initial 2014 NVPC forecast?

A. We have not estimated the effect for this initial filing. PGE will continue to monitor developments related to the approval of this new standard and will provide updates as necessary. The reserve requirements of this standard will be incorporated into MONET by updating certain parameters in the dynamic capacity enhancement described above.

Q. Please discuss the pending fuel transport contract updates.

A. PGE is currently pursuing the execution of new contracts for certain fuel transport services. An estimate of the rates currently expected for 2014 are included in our initial filing, which results in an increase to PGE's initial 2014 NVPC forecast. We expect that new agreements will be reached in time for our final scheduled contract update in November, as described above.

Q. What is the potential capacity resource contract update?

A. PGE's ongoing capacity request for proposals (RFP) seeks bi-seasonal (winter and summer) capacity of 200 MW and 150 MW of winter-only capacity (the capacity RFP is combined with PGE's energy RFP in OPUC Docket No. UM 1535). It is possible that a capacity resource selected from this RFP could be in the form of a power purchase agreement with an effective date in 2014. PGE will continue to evaluate other products available in the market to help fulfill our expected need for capacity resources. In the case that a contract is executed, we will include the contract in an update filing in as timely a manner as possible in order to enable review by parties to this proceeding.

J. Changes to Schedule 125 and Schedule 126

Q. Does PGE propose adjustments to Schedule 125 to reflect the updates discussed above?

A. Yes. PGE's proposed revisions to Schedule 125 reflect the updates to our wind energy forecast methodology and emission control chemical costs we discussed above. We also propose that wind integration costs, such as day-ahead forecast error cost, be updated to reflect the expected test year operating environment.

Q. Does PGE make any other changes to Schedule 125?

A. Yes. We make one additional change to Schedule 125, which clarifies a revision authorized in UE 215 (Commission Order No. 10-410, page 4). In that Order, the Commission adopted the Stipulation in which, "(t)he Stipulating Parties also agreed that the estimated costs of transmission losses will be allowed to change dynamically with the dispatch modeling for the Colstrip and Port Westward plants." Our change to Schedule 125 more accurately reflects that Order.

Q. Does PGE make any other changes to Schedule 126?

A. Yes. Our proposed changes to Schedule 126 update the definition of NVPC for inclusion of costs related to emissions control chemicals, consistent with our proposed changes to Schedule 125.

IV. Comparison with 2013 NVPC Forecast

Q. Please restate PGE's initial 2014 NVPC forecast.

A. The initial forecast is $639.2 million.

Q. How does this 2014 NVPC forecast compare with the 2013 forecast utilized to develop power costs in UE 250 and approved in Commission Order No. 12-397?

A. Based on PGE's final updated MONET run for the 2013 test year, the NVPC forecast was $651.1 million, or $34.32 per MWh. The initial 2014 forecast is $639.2 million, or $33.45 per MWh, which is approximately $0.87 per MWh less than the final forecast for 2013.

Q. What are the primary factors that explain the decrease in NVPC forecast for 2014 versus the NVPC forecast for 2013 in UE 250?

A. As Table 3 demonstrates, multiple factors contribute to the decrease:

Table 3
Factors in Forecast Power Cost Difference 2014 vs. 2013
($ Million)

Element	**$ Effect***
Hydro Cost and Performance	1.8
Coal Cost and Performance	29.5
Gas Cost and Performance	-38.1
Wind Cost and Performance	1.9
Contract and Market Purchases	-16.4
Market Purchases for Load Change	4.0
Transmission	8.0
Lower Market Price	-2.7
Total	**-$11.9**

* Numbers may not total due to rounding.

Key among these factors is the significant reduction in power costs related to gas-fired generation. Favorable movements in the market prices for natural gas and power lead to increased dispatch of PGE's gas-fired resources, and a reduction to the NVPC forecast. This reduction relative to PGE's final 2013 NVPC forecast includes mark-to-market on gas financial contracts. Various elements of Boardman operations (including the biomass test burn, the cost of emissions control chemicals, and the expected cost increases associated with certain contracts) increase the cost, and reduce the amount, of generation in this initial filing.

V. Qualifications

Q. Mr. Niman, please describe your qualifications.

A. I received a Bachelor of Science degree in Mechanical Engineering from Carnegie-Mellon University and a Master of Science degree in Mechanical Engineering from the California Institute of Technology. I am a registered Professional Mechanical Engineer in the state of Oregon.

I have been employed at PGE since 1979 in a variety of positions including: Power Operations Engineer, Mechanical Engineer, Power Analyst, Senior Resource Planner, and Project Manager before entering into my current position as Manager, Financial Analysis in 1999. I am responsible for the economic evaluation and analysis of power supply including power cost forecasting, new resource development, least-cost planning, and avoided cost estimates. The Financial Analysis group supports the Power Operations, Business Decision Support, and Rates & Regulatory Affairs groups within PGE.

Q. Ms. Peschka, please state your educational background and experience.

A. I received a Bachelor of Arts degree in Finance from Portland State University. I have been employed at PGE since 1999 in the following positions: Risk Management Analyst, Manager of Risk Management Reporting & Controls, and my current position General Manager of Power Operations. Before joining PGE, I worked at PacifiCorp from 1980-1999 in various retail, wholesale, planning, and mergers and acquisition positions. In my current position, I am responsible for managing the Power Operations group that coordinates the NVPC portfolio over the next five years.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
401	List of MFRs per OPUC Order No. 08-505
402C	February 15 Initial Filing MONET Output Files and Assumptions Summary

Minimum Filing Requirements
July 7, 2008

General

The Minimum Filing Requirements (MFRs) define the documents to be provided by PGE in conjunction with the Net Variable Power Cost (NVPC) portion of the Company's initial (direct case) and update filings of its General Rate Case (GRC) and/or Annual Update Tariff (AUT) proceedings.

The term "Supporting Documents and Work Papers" as used here means the documents used by the persons doing the NVPC forecasting at PGE to develop the final inputs to Monet and the final modeling in Monet for each filing. This may include such items such as contracts, emails, white papers, studies, PGE computer programs, Excel spreadsheets, Word documents, pdf and text files. This will not include intermediate developmental versions of documents that are not used to support the final filing. Documents will be provided electronically where practical.

In cases where systems change or are replaced in the future, such as BookRunner, the MFRs will continue to provide substantially the same information as provided in PGE's 2009 GRC (UE-198).

PGE will take reasonable steps to ensure that the MFRs can be made available to CUB and ICNU at the time of the filing, rather than these parties having to wait for the OPUC to approve the protective order in the case.

Delivery Timing

In either an AUT year (April 1 initial filing) or a GRC year (Feb. 28 initial filing), at a minimum the following portion of the Direct Case Filing MFRs will be delivered with the initial filing:

- Summary Documents (Items 1-6)
- Modeling Enhancements and New Item Inputs (Item 14) – not applicable in AUT year
- Miscellaneous Item 15d - re: Testimony and Exhibits provided on the CD

The remainder of the Direct Case Filing MFRs will be delivered with the initial filing if practical, or no later than fifteen days after the filing (e.g. March 15 in a GRC year, April 15 in an AUT year).

For all update filings, Update Filing MFRs will be delivered with the update filing with the following exception. For the April 1 GRC Update Filing in a GRC year, the delivery of Item 23 will be made with the filing if practical, or no later than fifteen days after the filing (e.g. April 15).

Direct Case Filing

Applicability

- Applies to GRC Initial Filing (e.g. February 28) in a GRC year
- Applies to AUT Initial Filing (i.e. April 1) in a non-GRC year

Summary Documents

1. Monet model for the final step
2. Hourly Diagnostic Reports for the final step
3. Step Log showing NVPC effects of modeling enhancements, modeling changes, addition of new items or removal of items from the prior year rate proceeding (GRC or AUT), and other major updates that PGE believes the parties would want to see identified separately, such as updating the hydro study.
4. Output/Assumptions Summary Report comparable to that provided for the 2009 GRC
5. Executable files, any other files needed to run Monet, and installation instructions
6. Identification of the operating system PGE uses to operate Monet

Supporting Documents and Work Papers for the Following

7. Forward Curve Inputs. Consists of:
    a. Electric curve extract from Trading Floor curve file
    b. Gas curve extract from Trading Floor curve file
    c. Canadian/US Foreign exchange rate (F/X Curve) from Risk Management
    d. Model run for hourly shaping of monthly on/off-peak electric curve (Lydia Program)
    e. Oil forward curve
8. Load Inputs. Consists of:
    a. Monthly load forecast from Load Forecast Group
    b. Hourly load forecast from Load Forecast Group
    c. Copy of the loss study used by Load Forecast Group to develop busbar load forecast
9. Thermal Plant Inputs
    a. Capacities
    b. Heat Rates
    c. Variable O&M

        This includes any other cost or savings components modeled as part of Variable O&M, such as incremental transmission losses, SO_2 emission allowances (emission allowance $/ton price forecast, plant emission factors lb/MMBtu), etc.
    d. Forced outage rates
    e. Maintenance outage schedules and derations
    f. Minimum capacities
    g. Operating constraints
    h. Minimum up times
    i. Minimum down times
    j. Plant testing requirements
    k. Oil usage volumes
    l. Coal commodity costs
    m. Coal transportation costs
    n. Coal fixed fuel costs classified as NVPC items

        Includes items such as: Colstrip Fixed Coal Cost and the following Boardman costs: Rail Car Mileage Tax, Coal Sampling, Rail Car Lease, Rail Car Maintenance, Trainset Storage Fee, and Coal Car Depreciation
10. Hydro Inputs
    a. Monthly energy for all Hydro Resources

        This will include the results of PGE's most current study using the Pacific Northwest Coordination Agreement (PNCA) Headwater Benefit Study. Note that this program is not the property of PGE and should be obtained from the Northwest Power Pool. Provide the PGE version of the PNCA model inputs, so that if the Parties obtain the PNCA model, they would have the inputs needed to reproduce PGE's study.
    b. Description of logic for hourly shaping where applicable
    c. Usable capacities where applicable
    d. Operating constraints modeled
    e. Hydro maintenance derations
    f. Hydro forced outage rates (not currently modeled)
    g. Hydro plant H/K factors
    h. Spreadsheet demonstrating how the hydro energy final output from the PNCA study is adjusted to arrive at the monthly energy output on the PwrAEOut sheet
11. Electric and Gas Contract Inputs
    a. Copy of contract for each long-term (5-year or greater term) or non-standard power contract modeled in Monet.

        For some contracts, this may consist of a term sheet rather than a full contract, depending on what was deemed reasonably necessary by the power modelers to model the contract in Monet.
    b. BookRunner extracts for the test year of:

        Electric Physical Contracts
        Electric Financial Contracts
        Gas Physical Contracts

Gas Financial Contracts
F/X Hedge Contracts

c. Copy of each firm gas transportation or storage contract modeled in Monet
d. List of the PURPA QF contracts modeled in Monet
e. List of the long-term (5-year or greater term) or non-standard contracts modeled in MONET that were not included in PGE's most recent GRC or AUT.
f. Gas transportation input spreadsheet or its successor/equivalent
g. Website snapshots input to the gas transportation spreadsheet
h. Other Supporting Documents and Work Papers for contracts modeled in Monet, including any items showing on the Monet Cost and/or Energy Output reports not covered above. Could include structured contracts, option contracts, etc.
i. Coal contracts: Covered above under Thermal Plant Inputs
j. Amortizations of regulatory assets or liabilities modeled in the Contracts section of Monet

12. Wheeling Inputs
    a. Supporting Documents and Work Papers for all wheeling items modeled in Monet
13. Wind Power Inputs. Includes but not limited to:
    a. Monthly energy
    b. Hourly energy
    c. Maintenance
    d. Forced outage rates
    e. Integration costs, royalties, other costs and elements modeled
14. Modeling Enhancements and New Item Inputs
    a. Supporting Documents and Work Papers for all modeling enhancements and new items modeled in Monet.
    b. Includes modeling or logic changes, changes to the methodology used to compute data inputs or other type of enhancement to the Monet model.
    c. Modeling revisions, refinements, clean-ups etc. that do not affect NVPC under any conditions will not be considered to be modeling enhancements.
15. Miscellaneous
    a. Line Item Adjustments to Monet such as OPUC orders, settlement stipulations, others
    b. Identification of all transactions modeled in Monet that do not produce energy
    c. Items in Monet not covered elsewhere above
    d. For all testimony and exhibits provided on the CD in pdf format, provide the testimony in searchable pdf format, and provide any exhibits created in Excel in the original Excel format when available to PGE.

<u>Historical Operating Data</u>

16. Hourly extract of data from PGE's Power Scheduling and Accounting System showing actual hourly energy values for the most recent Four-Year Calendar Period of the following:
    a. Generation from each coal, gas, hydro and wind generating plant modeled in Monet. Note that Colstrip Units 3 and 4 generation is aggregated in PGE's system, and the Mid-C contract generation is similarly aggregated.
    b. Long-term (>5 years) electric contract purchases, sales and exchanges modeled in Monet.
17. Table showing the actual monthly generation of each PGE coal, gas, hydro and wind generating plant modeled in MONET, from the period 1998 through the last calendar year.
18. Monthly compilations of actual NVPC produced by PGE for the most recent calendar year.

Update Filings

19. Monet model for the final step
20. Hourly Diagnostic Reports for the final step
21. Step Log showing effect on NVPC of each update step since the last filing
22. Output/Assumptions Summary Report comparable to that provided for the 2009 GRC
23. For each Monet update step:
    a. Text description of update, including identification and location of input changes within Monet.
    b. Excel file containing Monet standard output reports (PwrCsOut, PwrAEOut, PwrEnOut) and PC Input sheets.
    c. Supporting Documents and Work Papers for the update step
24. For all testimony and exhibits provided on the CD in pdf format, provide the testimony in searchable pdf format, and provide any exhibits created in Excel in the original Excel format when available to PGE.

Exhibit 402C

Confidential

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 262

Compensation

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Arleen Barnett
Joyce Bell
Jardon Jaramillo

February 15, 2013

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I. Introduction

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

A. My name is Arleen Barnett. My position is Vice President, Administration. My responsibilities include establishing compensation policy and employee policies, improving the work environment, overseeing safety and health programs, employee relations, managing employee development, and overseeing Business Continuity, Security, and Records Management.

My name is Joyce Bell. My position is Director of Compensation and Benefits in the Human Resources Department.

My name is Jardon Jaramillo. My position is Senior Investment Analyst in the Corporate Finance Department.

Our qualifications are included at the end of this testimony.

Q. What is the purpose of your testimony?

A. Our testimony presents and explains PGE's compensation costs for the 2014 test year and describes the changes to our compensation policies and plans since 2011. Total compensation costs include base wages and salaries, incentive pay, and employee benefits. We also present and explain PGE's proposed pension cost recovery and pension investment strategy, which will limit price volatility for customers.

Q. What are PGE's expected total compensation costs in 2014?

A. PGE forecasts approximately $316.4 million in total compensation costs for 2014, with the increase relative to 2011 driven primarily by the costs of benefits, particularly pension and health related. Table 1 summarizes the costs.

Table 1
Estimated Total Compensation Costs ($Millions)

Component	**2011 Actuals**	**2014 Test Year**
Wages & Salaries	$204.6	$219.4
Incentives	16.2	9.1
Benefits	64.4	88.0
Total Compensation	**$285.2**	**$316.4***

* Numbers may not sum due to rounding

The increase in wages and salaries since 2011 is due to market-driven wage and salary adjustments ($14.8 million). Test year incentive costs are $9.1 million reflecting 50% of test year costs (discussed in Section III). Benefits reflect continued increases in medical premiums ($6.6 million) and pension funding requirements ($14.4 million).

Q. What is PGE's total compensation philosophy?

A. PGE's philosophy is to provide compensation sufficient to attract and retain highly qualified employees necessary to provide safe and reliable electric service at a reasonable cost. At the same time, PGE actively controls costs by targeting our compensation program attributes and costs to reflect market median conditions.

Q. What major challenges influence the development of PGE's compensation philosophy?

A. PGE faces a number of challenges including:

- Recruiting;
- Rising health care costs;
- An experienced but aging workforce, resulting in an increasing and significant number of retirements;
- Changes in legislation; and
- Market forces.

Q. Has PGE developed responses to these challenges?

A. Yes. PGE has developed responses to each of these five challenges.

Q. Please describe PGE's approach to the first challenge – recruiting.

A. PGE faces significant challenges in recruiting and hiring that are common to the industry. Currently, PGE's major recruiting challenges are in the areas of engineering, IT security, senior analysts, and skilled trade positions such as metermen and power plant control operators. The market is very competitive for skilled professionals in those fields and recruited employees tend to have already been gainfully employed and, in most cases, have long tenure. Additionally, at PGE a majority of these positions are occupied by employees who are nearing retirement, adding pressure to PGE's recruiting efforts. In difficult to fill positions, PGE frequently enlists the services of contingency-based search firms and may offer wages in excess of the mid-point of our pay-guides, in addition to a few other increased benefits. More recently, the shortage of highly skilled professionals has resulted in PGE employing a number of individuals on work visas. With a recovering economy and as changing technologies require new, in-demand skill sets, we expect recruiting challenges to continue, as competition for highly skilled positions continues to increase.

Fortunately, PGE continues to be seen as an employer of choice for many people, which has helped us fill part-time and entry-level positions. We also have a popular summer hire program that helps to develop entry-level engineering, business, and other professional candidates.

Q. How does PGE combat the second challenge – rising health care costs?

A. PGE aggressively negotiates with vendors for favorable terms for provider contracts and outside services. PGE also negotiates and implements new plans that offer cost efficiencies. For example, our new Kaiser high deductible plan, discussed in Section III, lowers costs by providing a high deductible alternative. In addition, PGE performs internal studies to understand which employee health issues are contributing the most costs. PGE then develops targeted wellness programs designed to reduce long-term costs by lowering employee health risk factors. Finally, as health plan costs rise, because employees share the costs, they also realize an increased burden, aligning their interests with PGE's to minimize costs.

Q. Please describe how PGE is planning to meet the third challenge – an aging workforce.

A. Approximately 45% of PGE's current workforce will be eligible to retire (i.e., be at least 55 years of age and have at least five years of service) by the end of 2014. While in 2010 there were 54 retirements, 2012 almost doubled that number with 102 retirements. We currently estimate that PGE will see approximately 120 (or 5% of PGE's workforce) retirements per year for the next 5 years, which is significantly more than in the past. If the economy does begin to improve dramatically, this number could grow considerably higher, placing additional strains on PGE's operations and recruiting efforts.

Critical positions are expected to face significant retirements in coming years. Our response is to continue to recruit and train employees to fill vacancies in positions that have a high impact on the organization, have long learning curves, and are hard to fill. Examples of these critical positions are specialized utility positions such as transmission and reliability specialists and engineers, standards and electrical engineers, senior-level skilled crafts persons such as line and substation technicians, and senior-level utility analysts and specialists. Additionally, we continue our workforce development through the support and involvement in regional engineering programs, development of skilled trades, and outreach efforts in educational institutions to develop the current and future pool of workers.

Q. Please describe the changes in legislation and market forces and what PGE is doing to lessen their impact.

A. New federal legislation including the Pension Protection Act and the Patient Protection and Affordable Care Act have had and will continue to have dramatic impacts on the costs of PGE's benefit plans. In addition, current market forces driven by the Federal Reserve have created unusually low interest rates, which reduce discount rates used to calculate PGE's liabilities for our pension and retiree medical plans. Though beginning to change, recent stock market volatility and other financial forces have also led to employees retiring later than expected, creating challenges such as workforce redesign and improvement. In response to these challenges, PGE has closed its pension plan to new hires, begun a redesign of its medical plans (discussed in Section III), reduced benefit costs through evaluation of outsourced contracts and plan provisions, and implemented voluntary early retirement plans for employees in areas of PGE undergoing organizational change.

II. FTEs and Wages & Salaries

Q. What are the major components of PGE's total wage and salary revenue requirement?

A. Total wages and salaries are comprised of the number of full-time equivalents (FTEs) and the market-based pay structure.

Q. Please describe how PGE determines the number of FTEs required for the test year.

A. As part of the annual budgeting process, managers determine the number of labor hours in each position type that are required to accomplish their departments' work. PGE then converts the total labor hours into FTEs by dividing total labor hours by the number of work hours during the year. For example, an employee hired mid-year would be budgeted as one-half (or 0.5) FTE. As we discuss later, consistent with UE 215, we then make an adjustment for a normal amount of vacancies that occur throughout the year. For historical periods, FTEs reflect the actual number of hours worked divided by the number of work hours during that year.[1] Table 2 provides PGE's actual total FTEs (excluding overtime) for 2011 and forecast for 2014.

Table 2
Full-Time Equivalents

PGE FTEs (straight time)	**2011 Actuals**	**2014 Test Year**
Administrative and General	629.9	605.0
Customer Service/Accounts	409.4	422.7
Generation	452.4	483.3
Transmission & Distribution	1,051.8	1,014.7
Total FTEs	**2,543.5**	**2,525.7**

Q. Please explain how FTEs have changed from 2011 to 2014.

A. Overall FTEs have decreased by 17.9 from 2011 to 2014. This overall decrease is a result of PGE's focus on continuous improvement, efficiency, and cost effectiveness throughout all areas of the organization (see PGE Exhibit 200 for details). Due largely to the above

[1] All hours over 2080 per position, per year are excluded.

mentioned focus, FTE decreases are realized in PGE's administrative and general and transmission and distribution areas. The increase of FTEs in customer service and production is due largely to increases in regulation and compliance outside of PGE's control along with major projects focusing on improved customer experience. If not for PGE's company-wide focus on and commitment to continuous improvement, efficiency and cost effectiveness, the increases in customer service and generation would have been greater. PGE Exhibit 501 provides a list of FTEs by department for 2010 (actuals) through 2014 (test year forecast). Below is a summary of the primary FTE changes and references to testimony where they are described in more detail.

- 24.9 reduction in A&G/IT (PGE Exhibits 600 and 1000)
- 13.3 increase in Customer Service/Accounts (PGE Exhibit 900)
- 30.8 increase in Generation (PGE Exhibit 700)
- 37.1 reduction in Transmission and Distribution (PGE Exhibit 800)

While PGE's annual customer growth rate is forecasted to be 0.7% from 2011 to 2014, PGE's FTEs are forecasted to decrease by 0.2% annually over the same period.

Q. Please describe how PGE determines its pay structure.

A. In keeping with PGE's total compensation philosophy, PGE routinely compares its wages and salaries to the relevant markets. To do this, we collect a wide variety of compensation studies from various organizations and experts. These data are then used to benchmark the salary ranges of various positions against similar PGE positions. PGE performs regression analyses using these data to determine where the mid-point for each position classification lies. Actual salaries for each position level must fall within a specific range of PGE's pay structure as determined through the setting of these mid-points. Recognizing that each company can be in a different position regarding workforce age and experience, we compare salary range mid-points rather than salaries paid. This provides a more accurate comparison of salary structures. Consistent with industry standards, an employee's actual salary can vary from 80% to 120% of the mid-point. The actual salary level within a range is dependent on a number of factors including performance and experience. The consistent use of this practice ensures our current and prospective employees are fairly compensated while costs are controlled. In 2012, we compared our hourly non-union and salaried non-officer positions with the market. Our study showed that PGE's wage and salary structure is highly correlated with the market, indicating a well-designed, market-based wage and salary structure. The details of this study are provided in our work papers.

Based on the market surveys and Bureau of Labor Statistics Data, PGE forecasts a 2.4% annual increase in overall wages and salaries from 2011 to 2014. Table 3 summarizes total wage and salary costs for 2011 and 2014.

Table 3
Total Wages & Salaries ($000)

PGE Wages & Salaries (straight time)	**2011 Actuals**	**2014 Test Year**
Administrative and General	$56,463	$60,538
Customer Accounts	16,575	19,176
Customer Service	8,590	10,056
Generation	38,183	42,975
Transmission & Distribution	84,774	86,606
Total Wages & Salaries	**$204,586***	**$219,352***

* Numbers may not sum due to rounding

Q. Has PGE made any adjustments to arrive at its 2014 FTEs and wages and salaries figures?

A. Yes. To account for vacancies and/or unfilled positions, PGE has lowered its base budget wages and salaries by $5.0 million. We then made another $1.0 million adjustment to reflect savings expected from "myTime," PGE's new time collection system. The adjustment for vacancies and/or unfilled positions translates into a 56.3 FTE reduction, whereas the myTime (see PGE Exhibit 1000 for further details) adjustment is strictly an adjustment to wages and salaries, not FTEs. Additionally, there are specific FTE reductions in Generation, Transmission and Distribution, and Customer Service that translate to a 24.6 FTE reduction and an approximate $2.7 million reduction of base budget wages and salaries. The figures in Table 2 and Table 3 include these reductions.

Q. Did PGE recently renegotiate its contract with the IBEW Local No. 125 (the Union) including changes in compensation and benefits?

A. Yes. In 2012, PGE completed negotiations with the Union to extend the term of the March 2009 collective bargaining agreement (CBA) through February 2015. The CBA establishes a level of compensation for bargaining employees including wages, medical and retirement benefits, which are competitive and approximate the 50th percentile of the market.

Q. Were there any material changes to compensation and benefits in the contract extension?

A. Yes. The Union agreed to reduce their wage increase for both 2013 and 2014 by 0.5% in order to maintain a 90/10 cost share structure for active employee health and dental benefits.

Q. Does this tradeoff affect the Union's overall total compensation cost structure?

A. No. Viewed as a total package, bargaining employee's compensation and benefits continue to approximate the 50th percentile of the market. Section IV of this testimony discusses this trade-off in more detail.

III. Incentives

Q. How does PGE define incentive pay?

A. Incentives are not bonuses; rather, they are part of a competitive total compensation package where high performing employees are rewarded with a larger total annual compensation package. Incentive pay places a portion of employee pay at risk, making it dependent on their performance and quality of output.

Q. What is PGE's strategy for incentive compensation?

A. As with wages and salaries, PGE's strategy is to provide incentive pay that attracts, retains, and motivates employees. Foundationally, the incentive goals for all participants stem from PGE's corporate scorecard goals, which support our strategic direction, our commitment to core principles and continuous improvement.

Q. How does PGE determine the structure and target percentages for incentives?

A. PGE monitors the employment market and acquires information regarding incentive compensation program design practices. Then, consistent with our total compensation program design, PGE's targets are set at the 50th percentile, or middle of the market. Even though it is a small part of PGE's total compensation, incentive pay is very important; it allows PGE to remain competitive in the labor market <u>and</u> encourages employee performance and productivity. PGE's incentive programs align employee goals with shared customer and company goals to reduce power costs, improve customer satisfaction, and preserve PGE's financial stability.

Q. What fraction of PGE's total compensation are incentives?

A. The amount of incentive pay on which we are requesting recovery is approximately 2.8% of PGE's 2014 total compensation. Table 4 provides detailed actuals for 2011 and forecast for 2014.

Q. Did you exclude a portion of incentive plan costs from this case?

A. Yes, we removed 100% of the cost of officer stock incentives and 50% of the cost of incentives for all other plans. These adjustments are reflected in Table 4 below.

Q. Why did PGE make these adjustments?

A. We made these adjustments to mitigate the overall size of the rate increase. PGE has worked diligently to design incentive plans that fully benefit customers, provide reasonable incentive to both attract and retain qualified individuals, and to achieve corporate goals. This minimizes turnover, increases efficiency, and produces positive financial results – all goals that directly, positively impact PGE's costs to customers. While we have made these adjustments in this filing, we still believe that all of these costs are appropriate.

Table 4
Total Incentives ($000)

Incentives Component	2011 Actuals	2014 Test Year
Performance Incentive Compensation	$5,884	$4,916
Annual Cash Incentive	6,000	3,100
Stock (long-term incentive plan)	3,954	922
Notables and Miscellaneous	393	129
Total Incentives	**$16,232**	**$9,066**

A. Performance Incentive Compensation

Q. What is the Performance Incentive Compensation Plan?

A. The Performance Incentive Compensation (PIC) Plan is PGE's incentive program for most (approximately 1,600) non-bargaining employees.

Q. Please explain how the PIC plan aligns employee performance measures with customer interests.

A. PGE aligns its PIC plan with customer interests by basing the incentive pool on two equally weighted customer-focused goals:

- Individual or Team Scorecard Goals: These scorecard goals are designed to stretch performance and promote individual growth and development, while aligning with corporate operational goals (e.g., efficiency, operational standards).
- Financial Performance: Financial strength can reduce customer rates through lower borrowing costs and, thus, lower cost of capital.

Actual award amounts are based on employees' incentive targets and performance relative to these goals.

B. Annual Cash Incentive

Q. What is the Annual Cash Incentive (ACI) Plan?

A. PGE's ACI Plan is an incentive plan for executives and key non-bargaining employees whose contributions have a strategic and measurable impact on the success of PGE's goals.

Q. Please describe the ACI plan's operational goals and how they align employee performance measures with customer interests.

A. PGE aligned its ACI plan with customer interests by basing the incentive payouts on PGE's success in achieving four customer-focused goals described below. Effective in 2013, the first three goals are weighted and determine 50% of the total payout awarded. The first three goals are then added with the final goal of Financial Performance. Because of this change in design we have included 50% of all ACI costs in our total test year incentive costs for this rate case. This is consistent with OPUC Order No. 97-171, a US West Communications (USWC) rate case, which states in part: "If in a future rate case USWC submits employee incentive plans with goals that benefit both ratepayers and shareholders, we will include those expenditures in revenue requirement."[2] A copy of the new 2013 ACI design is included in our work papers. ACI goals are:

- Customer Satisfaction: This goal measures the overall satisfaction of PGE's retail customer groups using results from 1) the average quarterly percent rating of the Market Strategies International (MSI) study for residential customers, 2) the average semi-annual percent rating of the MSI study for business customers, and 3) the annual results from the TQS Research, Inc. National Utility Benchmark of Service to Large Key Accounts. The results of the three measures are weighted based on revenue from each retail customer group, respectively. High customer satisfaction rates are a key indicator that PGE is providing customers high quality service at a reasonable price.
- Electric Service Power Quality and Reliability: This goal uses annual results of the company's 1) System Average Interruption Duration Index (SAIDI), the average outage duration for each customer served, 2) System Average Interruption Frequency Index (SAIFI), the average number of interruptions that a customer would experience, and 3) Momentary Average Interruption Frequency Index (MAIFI), average number of momentary interruptions that a customer would experience. Both SAIFI and MAIFI are weighted at 15% of this goal, while SAIDI is weighted at 70% of this goal.
- Generation Availability: This goal measures the amount of time that our generating plants are available to produce energy. Plant availability positively

[2] OPUC Order No. 97-171, p. 74

influences power costs by ensuring that the lowest cost resources are available for dispatch.

- Financial Performance: This goal measures actual net income relative to a net income target established by our Board of Directors. PGE's financial strength will reduce customer prices through lower borrowing costs and, thus, a lower overall cost of capital. Financial strength also supports PGE's access to capital to support investments that benefit customers.

Q. Why did PGE change ACI's design in 2013?

A. We believe it is important for our incentive plans to directly support PGE's strategic direction, our commitment to our core principles and continuous improvement. Improvements in efficiency and process benefit both customers and shareholders. Through changing the payout structure, PGE has rebalanced the operational goals within the ACI program, further encouraging our employees to improve their daily processes and PGE's overall efficiency. Customers benefit from lower expenses and a more efficient company, while the expected higher net income helps PGE to achieve and maintain a competitive stock price and access to capital. Copies of the most recent incentive plans are included in our work papers.

Q. Have there been any other changes to PGE's incentive plans?

A. No. The PIC plan and incentive plans for Biglow Canyon, Port Westward and Coyote Springs used in 2011 remain in effect. We have found these plans to be effective in motivating employees to pursue efficiencies and maintain a high level of operations.

C. Other Plans

Q. Please describe PGE's long-term incentive program.

A. PGE initiated its stock incentive plan in 2006 and it reflects current market practice; many publicly traded companies (including most utilities) provide long-term incentives to promote performance and retention of directors, officers, and key employees. These awards are earned and paid out in three-year cycles. The Commission, in docket UF 4226, approved this stock issuance and summarized the goals of the plan: "the Plan is part of the Company's overall compensation package and is intended to provide incentives to attract, retain, and motivate officers, directors, and key employees of the Company."[3] PGE forecasts approximately $0.9 million for the 2014 total long-term incentive expense.

Q. Does PGE have other programs that reward employees' exceptional performance?

A. Yes. Notable Achievement Awards (Notables) and other miscellaneous awards are given to employees on a case-by-case basis for exceptional performance. Notables are distributed to recognize employees' outstanding work on a specific project or task. PGE's 2014 forecast for Notables is $129,000.

At times, and in specific situations, we have also employed other types of incentives such as signing bonuses and retention payments to obtain difficult-to-locate talent, in periods of critical skill competition, to ensure the completion of important tasks, or to hold employees in cases of future layoffs (e.g., Trojan decommissioning). However, these types of incentives are not included in the 2014 test year.

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[3] OPUC Order No. 06-356, p.1.

IV. Benefits

Q. What is PGE's benefit compensation strategy?

A. PGE strives to maintain a benefits package that meets our employees' needs and balances the features and costs among programs, employee groups, PGE and the market. As with the other two compensation components (wages/salaries and incentives), PGE compares our benefits programs to the market and targets prevailing market attributes. PGE also uses market information to create innovative program designs to provide greater employee choice and improve our ability to control costs. As a result, we believe that our total compensation package is sufficient to attract and retain quality employees.

Q. What components comprise PGE's total benefits?

A. There are four major components: health and wellness, post-retirement, disability and life insurance, and miscellaneous benefits. These components are typical parts of our competitor companies' offerings. As shown in Table 5 below, PGE's total benefits costs are expected to increase 11% annually from 2011, driven primarily by health and pension costs. Excluding pension costs, the annual increase in benefits costs is 4.9%. These two drivers are discussed in more detail below and in Section V. We project 2014 employee benefit costs of $88 million.

Table 5
Total Benefits ($000)

Benefits Compensation Component	**2011 Actuals**	**2014 Test Year**
Health and Wellness	$36,784	$43,483
Disability and Life Insurance	3,218	3,486
Post-Retirement	22,715	39,680
Miscellaneous Benefits	1,084	721
Benefits Administration	625	642
Total Benefits	**$64,425***	**$88,011***

* Numbers may not sum due to rounding

Q. How is PGE mitigating the increases in benefit costs?

A. PGE uses several methods to mitigate the costs including: 1) negotiating with vendors for favorable contract terms; 2) modifying benefits plan structures to track market practice; and 3) using programs that encourage a healthy workforce.

Q. Can you provide examples of actions PGE took which mitigate benefit costs?

A. Yes. With the help of benchmarking data, we renegotiated our Retirement Savings Plan (RSP) administration contract in 2012, reducing the costs by approximately 50% and increasing the services received. PGE has also worked to reduce costs by renegotiating other vendor contracts. In 2012, we switched vendors for our Medicare supplement plan, resulting in lower company contributions to the plan saving approximately $6 million over the next 10 years, with $0.7 million of the savings recognized in both 2013 and 2014. Additionally, as we noted previously, when health care premiums rise, PGE employees share the increased cost.

PGE also adjusts program features to help control costs. For 2013, PGE has redesigned our medical plans in order to reduce rate increases. The redesign includes higher employee co-payments, deductibles, co-insurance, and a new high deductible plan for Kaiser. These and other changes within the redesign have reduced the budget for health and dental expenses by approximately $0.8 million.

PGE also compares outside services and insurance versus our own in-house capabilities and self-insurance. As a result, PGE moved to an in-house health and welfare administrative system that uses our existing capabilities. The annual savings associated with this change are approximately $0.3 million. Additionally, in 2011, when evaluating health and dental plans, PGE determined that self-insuring our MetLife dental coverage would cost less than the insured offer. This change resulted in a savings of approximately $76,000 over the insured offer in 2011 and lower rate increases since then.

Finally, PGE invests in internal health and wellness programs to help identify and lower health risk factors that reduce long-term medical issues and reduce plan costs. We provide tools and/or referrals for employees identified as high risk during our health screenings to lower their medical risks (e.g., diabetes, heart disease, high cholesterol, high blood pressure, etc.). PGE's medical vendors provide and encourage participation in wellness programs and disease management programs. These programs help reduce major medical events, which keep our medical premiums lower than they would otherwise be.

Q. Please explain why medical and dental benefits costs increased approximately $6.6 million from 2011 to 2014.

A. On a broad level, medical and dental costs continue to rise each year nationwide, not just in the Northwest or at PGE. According to new estimates from the federal government, national health spending is forecasted to account for nearly one-fifth of the U.S. GDP by 2021.[4] We strive to minimize those increases at PGE. The $6.6 million requested increase for medical and dental represents a 5.7% annual increase from 2011, which is an improvement relative to PGE's historical annual rate increase of 7% from 2006 to 2011. Higher premiums are the main drivers for the increased cost in PGE's medical and dental benefits. Medical and dental plan premium percent increases for non-bargaining employees are detailed in Table 6 below.

[4] http://capsules.kaiserhealthnews.org/index.php/2012/06/report-health-spending-will-climb-to-nearly-one-fifth-of-gdp/.

Table 6
Non-bargaining Medical & Dental Premium (% change)

	2011	**2012**	**2013**	**2014****
Kaiser Medical	7.0%	9.00%	7.70%	8.02%
Kaiser Dental	3.60%	0.00%	-5.20%	5.95%
Providence*	2.6-4.0%	19.8-22.1%	0.0-8.30%	8.55%
MetLife Dental	0.0%	6.10%	4.20%	6.00%

* Providence has 3 different plans. The changes above are ranges among the 3 plans.
** 2014 forecast provided by Mercer

Health care premiums for the main bargaining unit are a negotiated benefit and managed by a Taft-Hartley Trust. We forecast that bargaining employee medical and dental plan costs will increase approximately 6% in 2013 and 8% in 2014, based on a semi-annual survey of local insurance companies' annual claims cost trends performed by Mercer, PGE's benefits consultant. These rates are used by the insurance companies to project their insured renewal rates.

Q. What wellness expenses are included in the 2014 test year?

A. PGE forecasts approximately $0.4 million for wellness costs in 2014. PGE works hard to attain and maintain a healthy workforce. Our wellness programs are a big part of that effort. The programs[5] provide early detection of risk factors, intervention and management of health issues. These programs promote healthier lifestyles, which contribute to lower medical premiums, increased morale and productivity. Such programs include Energy for Life, AfterHours, and Get Moving, Get Healthy. Energy for Life health programs include biometric testing, health risk appraisals, professional health coaching, obesity management, wellness reimbursements and disease prevention. The AfterHours and Get Moving, Get Healthy Programs provide partial reimbursements to employees who engage in programs

[5] PGE's health and wellness programs are in line with the Oregon Governor's wellness initiative of 2008 and the Governor's 2012 priority health care objectives. Visit http://archivedwebsites.sos.state.or.us/Governor_Kulongoski_2011/governor.oregon.gov/Gov/P2008/press_103108.shtml and http://www.oregon.gov/Gov/priorities/Pages/healthy_oregon.aspx for more detail.

that promote engagement and support healthy lifestyles. Also included are occupational health services, which provide flu shots, health screening, and case management.

Q. PGE's benefits programs changed from "flex dollars" to a "fixed company contribution." How does a fixed company contribution work?

A. Beginning in 2012, PGE moved from what is known as a flex dollars allocation, which allows employees to choose which benefits to purchase from the total flex dollar amount, to a fixed company contribution, which allocates fixed amounts for medical, dental, and vision insurance. This change allowed PGE to bring our health and welfare administration in-house, reducing expenses.

Q. How do PGE's medical plan costs compare to market benchmarks?

A. Based on 2012 benefits studies by Towers Watson, PGE's non-bargaining medical costs moved slightly above that of the Electric/Utilities Industry by 3%. Towers Watson also performs a program efficiency study through comparing medical care costs across industries, adjusting for the composition of participants (age, gender, family size, etc.). PGE's costs per non-bargaining employee were 6% above the average cost per employee of this benchmark.

Q. Has PGE taken any steps since the 2012 benchmarking towards realigning its medical plan costs with middle of the market?

A. Yes. As described above, beginning in 2013, we have redesigned some of our health care plans in order to reduce PGE's medical plan costs. As part of the redesign, a new high-deductible plan was added and the co-pays, deductibles, and co-insurance for which employees are responsible were increased. We expect these program changes to return us to the industry average for the 2013 and 2014 benchmark studies.

Q. What is PGE's targeted premium ratio?

A. PGE targets an overall premium ratio of 85% company and 15% employee for non-union medical, dental and vision premiums. This ratio, as an average, is reflected in the fixed company contributions employees receive. Employees then pay the remainder of the costs. While our targeted premium ratio has stayed at 85/15, the program changes to co-pays, deductibles, and co-insurance described above reduce PGE's total medical costs.

Q. How do PGE's overall benefit costs compare to market benchmarks?

A. Based on the Towers Watson 2011 Energy Services BENVAL Study, a bi-annual comparison of benefit values (all open health and dental, post retirement, disability, and life insurance plans) among peer utilities with similar revenues, PGE's non-bargaining population is at the industry average for its overall benefit programs. Our bargaining employees rank slightly higher at about 6% above the benchmark. However, the 2012 extension to the collective bargaining agreement includes a reduction to 2013 and 2014 wage increases in order to maintain a 90/10 medical benefits cost sharing structure, offsetting the higher 90/10 structure. When factoring this wage reduction into the BENVAL Study, bargaining employee overall benefit costs also approximate the industry average.

Q. Please explain PGE's 2014 disability and life insurance benefit forecast of $3.5 million.

A. PGE's disability and life insurance benefits are comprised of union short-term disability insurance, long-term disability insurance, and retiree group life insurance for all employees.

PGE forecasts union short-term disability insurance costs of approximately $511,000 in 2014. This represents a 3.3% percent annual increase compared to 2011 and is the result of an 8% rate increase in the renewal of the union short-term disability contract in 2012, coupled with the union-negotiated wage increases for 2012 through 2014. Costs for 2013 and 2014 reflect our claims history. PGE's non-union, short-term disability expense is a part of payroll labor loadings, and is included in our wage and salary forecast.

PGE forecasts long-term disability medical costs for union and non-union employees to be approximately $1.6 million in 2014. PGE uses a forecast by Towers Watson, a third party actuary, to budget for these expenses. Actual long-term disability costs fluctuate from year-to-year. The actuarial forecasts are driven by factors such as the discount rate, health care trend assumptions, number of participants, and demographics of the participant population. The expense in a given year is calculated as the difference between the ending and beginning liabilities, plus the benefits actually paid by PGE in that year. PGE pays 85% of the health care benefits for non-union employees and 90% for union employees on long-term disability.

PGE forecasts retiree group life insurance costs to be approximately $1.3 million in 2014. The discount rate used by Towers Watson is based on a high quality bond benchmark that was reduced in 2012 from 5.35% to 3.93%. The lower discount rate increases PGE's liability. For union and non-union employees, PGE pays for a basic level of coverage for life insurance for retiree members. Active union and non-union members pay for their own life insurance.

Q. What is included in PGE's post-retirement benefits costs?

A. PGE classifies the Retirement Savings Plan (RSP) and the PGE Pension Plan as post-retirement benefits. For purposes of this testimony, we also present the Health Reimbursement Account (HRA) as a post-retirement benefit.[6]

[6] To comply with ERISA accounting guidelines, PGE classifies the HRA as a health and wellness benefit, even though employees do not receive the benefit until after retiring from PGE.

PGE's RSP costs are based on employee contributions and PGE's match and include an employer contribution for union employees and non-union employees hired after February 1, 2009. These costs change with base wage and salary levels and employee participation. From 2011 to 2014, costs associated with the RSP are expected to increase from $15.9 million to $16.5 million, or approximately 1.3% annually. This increase is a result of assumed wage and salary increases for 2013 and 2014 and is partially offset by the removal of a $1.00 per straight-time hour contribution for bargaining employees that PGE was making to the RSP. Under the new collective bargaining agreement, the contribution is now being made to the HRA. We discuss pension obligations in Section V.

PGE's HRA provides a post-retirement benefit to cover a portion of health care premium costs for employees who retire from PGE. For non-bargaining employees, only those who retire from PGE will receive any HRA benefit. For these employees, PGE places 0.5% of annual wages and salaries into a notional account for retiree HRA benefits. For bargaining employees, PGE now contributes $1.00 per straight-time hour into the HRA account. PGE forecasts total HRA costs to be approximately $3.4 million in 2014, which represents a 33% annual increase since 2011. This increase is primarily due to the shift of the bargaining employees' $1.00 per straight-time hour contribution to the employee's HRA. Without this change in accounting, HRA costs would increase by approximately $1.7 million, or 6.7% annually.

Q. Why are post-retirement benefits important?

A. Post-retirement benefits support employee recruitment and are an important retention device. Retirement-eligible employees are generally highly productive, and will work until full or close to full pension coverage. The retirement benefits encourage retention and help ensure knowledge transfers between retiring and new employees.

Q. What is PGE's 2014 cost for miscellaneous employee benefits?

A. PGE forecasts 2014 costs for miscellaneous benefits to be approximately $0.7 million. Miscellaneous benefits are additional, low cost tools that PGE uses to attract and retain employees. These tools help balance employer-provided benefits with the changing realities of our demographics and market position. PGE's miscellaneous benefits costs are primarily educational assistance and Service Awards.

- Education Assistance: $463,190 – This program reimburses employees for education that enhances learning and development. It can be applied to classes that lead to a certification or undergraduate/graduate degree as well as classes that enhance technical knowledge. This program increases PGE's number of qualified employees available to fill open positions. Sponsoring career development is also a prime recruiting tool and source of employee motivation and satisfaction, which also aids retention.
- Service Awards: $233,000 – As a retention and morale strategy, PGE honors employees for their years of service at five-year anniversary intervals, consistent with industry practice.

Q. What is PGE's 2014 cost for benefits administration?

A. PGE forecasts 2014 benefits administration costs to be approximately $642,000. This represents an annual increase of less than one percent since 2011.

V. Pension

Q. Please describe PGE's defined benefit pension plan.

A. PGE sponsors a non-contributory, defined benefit pension plan, of which substantially all participants are current or former PGE employees. As of December 31, 2012, the plan had approximately 4,244 participants, of which 2,259 are active and 1,985 are retirees or terminated vested.[7] Eligible individuals vest after five years of service and accrue benefits based on a number of factors, including years of service and final average earnings. Although the plan was closed to new employees in 2009, PGE's pension benefit obligation is expected to continue to increase over the next several years as remaining eligible employees vest.

Q. How do the benefits of PGE's pension plan compare to those of other utilities?

A. According to Towers Watson's 2007 BENVAL study, which was the last study performed prior to PGE closing its pension plan, the benefit offered by PGE's pension plan when compared to other open pension plans was below average (88.6%). See PGE Exhibit 502 for this comparison. Please note that the study does not identify the individual utilities' benefits, though the participants in the study group are known.

Q. How is the benefit employees receive determined?

A. Benefits are determined based on years of service to PGE and their base pay at the time of retirement. No overtime, incentives, or other pay is factored into this calculation. For example, a retiree with 30 years of service with a base salary equal to the median for 2011 retirees would receive approximately 34% of their final base pay as an annual pension benefit.

[7] Participants who have met the vesting requirements but have left PGE prior to reaching retirement age.

Q. Has PGE taken any actions to limit its pension benefit obligation?

A. Yes. Effective February 1, 2009, new non-bargaining employees are ineligible for the pension plan. Closing the plan reduces PGE's and its customers' future liability and exposure to market fluctuations. PGE previously closed the plan to new bargaining unit employees effective January 1, 1999. In addition, PGE has not granted a cost of living adjustment for retirees since 1994, limiting the adjustment to only those receiving less than the minimum benefit.

Q. What is the funded status of PGE's pension plan?

A. PGE must consider two different measures of funded status. First, for Pension Protection Act[8] (PPA) purposes, PGE's pension plan complied with a target 80% funded ratio as of December 31, 2012. We expect to contribute more than $180 million over the next ten years to continue meeting this commitment. Second, for Financial Accounting Standards (FAS) purposes, PGE's pension plan was 86% funded as of December 31, 2012. This compares to 97% as of December 31, 2011.

Q. How has PGE's pension assets performed relative to peer companies?

A. PGE pension assets have consistently outperformed similar funds, ranking in the top quartile of peer companies for the last five years.

Q. What are PGE's projections for expense, cash contributions, and the funded status of the pension plan for the next 15 years?

A. PGE's third-party actuary, AON Hewitt, estimated PGE's pension expense and cash contributions for the next 15 years. Confidential PGE Exhibit 503C contains estimates as of January 11, 2013.

[8] The Pension Protection Act of 2006 (Pub. L. 109–280), 120 Stat. 780.

Q. Can you explain what components make up pension funding requirements?

A. The two different funding requirements related to pension cost are FAS 87 pension expense and PPA cash contributions. Section A, below, describes them in more detail and how they affect PGE.

A. Pension Funding Requirements

1. Pension Expense (FAS 87)

Q. How is pension expense calculated?

A. Pension expense, more formally known as "FAS 87 net periodic benefit cost," [9] represents the cost of maintaining an employer's plan, and is reported on the company's income statement. Pension expense consists of the following components: service cost, interest cost, expected return on assets, amortization of prior service cost, and amortization of net gains or losses.

Q. What assumption does PGE use for its expected long-term rate of return?

A. PGE uses an expected long-term rate of return of 7.5%.

Q. How is PGE's expected long-term rate of return determined?

A. Based on the pension plan's asset allocation, the pension investment portfolio is expected to yield a long-term rate of return of 7.5%. This estimate is developed based on information provided by Mercer Investment Management Company. Investment returns in coming years are not expected to match the returns observed in the prior two decades, due to various macroeconomic factors.

Q. What assumption does PGE use for its discount rate?

[9] PGE records its pension expense based on Accounting Standards Codification (ASC) 715, "Compensation – Retirement Benefits," which prior to July 1, 2009, was known as Statement of Financial Accounting Standards No. 87 or "FAS 87."

A. PGE uses a discount rate of 4.35%, which is an average of the interest rates of a basket of long-term high quality AA-rated bonds. This methodology is determined in accordance with Generally Accepted Accounting Principles (GAAP).

Q. Why are these rates important?

A. The long-term rate of return and discount rate used, coupled with PGE's current pension assets, determines the level of PGE's pension costs for a given year.

Q. How sensitive are PGE's pension costs to changes in the long-term rate of return and the discount rate?

A. A 0.25% increase in the expected long-term rate of return on plan assets would decrease PGE's expected 2014 pension expense by approximately $1.3 million (prior to capitalization). A 0.25% reduction in the discount rate would increase PGE's expected 2014 pension expense by $2.2 million (prior to capitalization).

Q. What is PGE's forecasted 2014 pension expense?

A. PGE's 2014 pension expense is forecasted to be $36.5 million (or approximately $23.6 million after capitalization).

2. Cash Contributions (Pension Protection Act)

Q. Please summarize the requirements of the Pension Protection Act.

A. Signed into law in August 2006, the PPA creates minimum funding targets for private pension plans. Pension plan sponsors that do not meet these funding targets are required to contribute to their pension funds to comply with the requirements of the act. By contrast, pension expense is an accounting concept that is not used to determine legal funding requirements. The PPA's funding requirements are governed by various actuarial smoothing mechanisms, including revisions outlined in the Moving Ahead for Progress in the 21st Century Act (MAP-21) signed into law in 2011.[10]

Q. How much cash has PGE contributed to its pension plan pursuant to the Pension Protection Act?

A. As a result of the new funding requirements, PGE contributed a total of $30 million in 2010 and $26 million in 2011. PGE expects to contribute more than $180 million over the next ten years.

Q. Does PGE use the same assumptions for discount rate and expected long-term rate of return for pension expense and PPA funding requirements?

A. PGE uses the same expected long-term rate of return for pension expense and PPA funding. Discount rate assumptions are based on different methodologies as required by Generally Accepted Accounting Principles (pension expense) and IRS regulations (PPA funding requirements).

Q. Do the assumptions for calculating pension expense and PPA cash contributions differ?

A. Yes. There are two primary differences, one on the asset side and one on the liability side. On the asset side, for pension expense purposes, PGE must use the market value of the portfolio at December 31 of each year. For PPA purposes, PGE uses a multi-year asset smoothing method to calculate the average balance.

On the liability side, for pension expense purposes, PGE must use the discount rate as of December 31. For PPA purposes, PGE uses discount rates outlined as part of Employee Retirement Income Security Act (ERISA) regulations. For assets and liabilities, the PPA methodology helps smooth market volatility.

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[10] HR 4348, http://www.govtrack.us/congress/bills/112/hr4348/text.

Q. Why are these differences important?

A. They help to explain why a company's pension expense, as reflected on its income statement and the cash contributions it is legally required to make can differ considerably, and further justify why balancing accounts are appropriate for recovery of pension related costs.

B. Pension Cost Recovery

Q. What is PGE requesting regarding pension cost recovery?

A. We request that the Commission authorize the use of a balancing account. An appropriate balancing account would track differences between forecasted and actual pension expense and return on the prepaid pension asset[11] and would refund or collect the differences to customers, ensuring PGE does not over- or under-recover pension related costs. Confidential PGE Exhibit 503C contains a forecasted balancing account for 2014-2029 based on AON Hewitt's estimates.

Q. What amount is included in the test-year for pension costs?

A. Under the balancing account approach, PGE is requesting recovery of $19.8 million, assuming a 15-year amortization period.

Q. How does this compare to the recovery of pension expense without a balancing account?

A. Without a balancing account treatment, PGE's revenue requirement would include recovery of pension expense of $23.6 million, net of capitalization and a return on the average balance of cash contributions made in excess of pension expense of $90.9 million ("prepaid pension asset"). The use of a balancing account reduces PGE's revenue requirement request for 2014 by $14.5 million.

[11] Cash contributions made in excess of FAS 87 expense and not recognized on the income statement.

Q. Why did PGE use a 15-year amortization period?

A. This period of time serves the dual purposes of reducing PGE's request in this rate case while also amortizing the expected balance in a reasonable amount of time. The amortization period may be reevaluated in future general rate proceedings.

Q. Why would a balancing account be appropriate for pension costs?

A. A balancing account would provide PGE the opportunity to recover incurred pension expense and financing costs for cash contributions that have been made in excess of pension expense. Given the differences between pension expense and legally required PPA cash contributions, a balancing account ensures that PGE recovers only prudently incurred costs.

Q. Should a balancing account include a rate of return on the balance?

A. Yes. Earning a return on the balancing account balance recognizes the long-term nature of the plan and the opportunity cost of using these funds.

Q. How would PGE's customers benefit from a balancing account?

A. As mentioned above, use of a balancing account would reduce PGE's request in this case by approximately $14.5 million and ensure that PGE recovers prudently incurred costs over time. In addition, a multi-year amortization would minimize the volatility of costs to customers when compared to setting recovery to just the forecast in a given test year.

Q. Is PGE requesting the return of its prepaid pension asset?

A. Not at this time. However, absent regulatory intervention, the prepaid asset may take a long period of time to reach a zero balance. In addition, a significant expense would be incurred in the year the plan is terminated. Neither of these outcomes is desirable for PGE or its customers due to the considerable uncertainty.

Q. Will the generic pension proceeding (Docket No. UM 1633) inform the type of recovery PGE will receive in this general rate case proceeding?

A. Possibly. In NW Natural's most recent rate case, the Commission called for a generic proceeding for Oregon utilities to evaluate pension cost recovery (Order No. 12-408, p.5). Should the generic proceeding be completed during this proceeding its outcome could be incorporated.

Q. If PGE were granted recovery of only pension expense, wouldn't PGE's pension plan be made whole over time?

A. No. First, PGE's pension expense recovery is currently only updated during a general rate case. This leads to variations between what is included in rates and actual expense in the years between rate cases as well as the test year. Pension expense is expected to vary significantly from year to year over the next several years (see PGE Confidential Exhibit 503C). Second, PGE expects to make significant cash contributions to its pension plan pursuant to the Pension Protection Act. PGE must finance these contributions and pension expense does not provide recovery of PGE's financing costs. This has a detrimental impact on PGE's capital structure and earnings potential due to un-recovered financing costs. Both items adversely affect PGE's ability to attract necessary capital.

C. Pension Investment Strategy

Q. What is PGE's pension investment strategy?

A. As mentioned previously, PGE has taken steps to manage its pension benefit obligation and we work to align pension assets and pension liabilities to minimize volatility in pension expense and cash contributions. This will be accomplished by modifying the pension's asset allocation as the plan's funded status improves. The strategy is to ensure that changes in market performance or discount rates that result in an increase or decrease to the pension benefit obligation also result in a corresponding increase or decrease to the value of pension assets, thereby reducing pension expense and cash contribution volatility and their resulting impacts on customer prices.

Q. How is PGE's asset allocation expected to change over time under the new strategy?

A. PGE's pension assets are currently allocated as follows: 31% US Equities, 31% Non-US Equities, 33% Fixed Income, and 5% Private Equities. Over time, PGE will reallocate equity investments into fixed income investments in order to achieve the alignment between assets and liabilities, minimizing expense volatility. This alignment can be considered in terms of how much a pension's assets are "matched," or "hedged," against its liabilities. Currently, in PGE's case, pension assets are approximately 33% hedged, which is typical for similar plans. The allocation to fixed income will increase incrementally as the funded status of the plan improves, with as much as 80% of assets allocated to fixed income in a fully-funded plan. A fully funded plan with significant allocations to fixed income will decrease the volatility in pension expense and cash contributions by linking pension assets and liabilities.

Q. Why is PGE making this change and over what time period will it be implemented?

A. The PPA and recent market volatility have highlighted the need to make volatility reduction a key component of the pension investment strategy. PGE believes reducing pension expense and cash contribution volatility is in the best interest of both PGE and its customers over the long-term.

PGE is developing a strategy to increase the allocation to fixed income as the funded status improves over the next seven years. As PGE contributes cash required by PPA through 2020, we will increase the allocation to fixed income in accordance with a prudent investment policy. Allocation changes will likely be triggered by a predetermined funding level. For example, we may increase the fixed income allocation from 33% to 40% to lock in the benefit of significant contributions in 2015. Ultimate funding levels will be determined based on a prudent and deliberate investment philosophy.

Q. What changes has PGE made since the last general rate case?

A. In 2011, PGE increased the re-allocated fixed income securities from a portfolio of long-duration government and corporate bonds to a portfolio of only high-quality corporate bonds. We believe this allocation will improve the return on pension assets while controlling volatility in pension expense. In 2012, PGE re-allocated 8% of the portfolio from US Equities to Non-US Equities. We believe this re-allocation will result in higher returns and lower volatility while pension funding improves.

Q. What is the effect of changing the asset allocation on pension expense and cash contributions?

A. As we mentioned previously, the effect will be lower, less volatile pension expense and cash contributions. As PGE reallocates assets from equities to fixed income, we expect lower pension plan volatility coupled with a lower expected rate of return.

VI. Summary and Qualifications

Q. Please summarize your testimony.

A. PGE must provide a total compensation package sufficient to attract, retain, and encourage performance beneficial to PGE and our customers. Thus, PGE designs its total compensation program with reference to the labor markets in which we compete. This approach provides a total compensation structure, comprised of wages and salaries, incentives, and benefits, that as proposed will be competitive and cost effective.

Q. Ms. Barnett, please summarize your qualifications.

A. I received a Bachelor of Arts degree from Abilene Christian University, followed by a certification in Human Resources at Portland State University. I completed coursework toward an MBA at the University of Portland. As Vice President of Administration, I oversee Business Continuity and Security, and Human Resources areas.

After working in the California school system, I joined PGE in 1978 and have successfully bid and been selected for various positions at PGE. I became Vice President in 1998.

Q. Ms. Bell, please summarize your qualifications.

A. I received a Bachelor of Arts degree from the University of Pittsburgh. I received a Masters in Business Administration from the Joseph M. Katz Graduate School of Business, University of Pittsburgh. Prior to joining PGE, I worked at Fireman's Fund Insurance, Co. and American Express in finance; and at Baltimore Gas & Electric Company in the areas of finance and human resources. In 1988, I joined Portland General Electric and I have been Director of Compensation and Benefits since 1998.

Q. Mr. Jaramillo, please summarize your qualifications.

A. I received a Bachelor of Arts degree in economics from Northwest Nazarene University and am a Certified Public Accountant. Prior to joining PGE, I worked at Deloitte & Touche, where I served various public utilities as an external auditor and worked in mergers and acquisitions consulting. I joined PGE in 2011.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

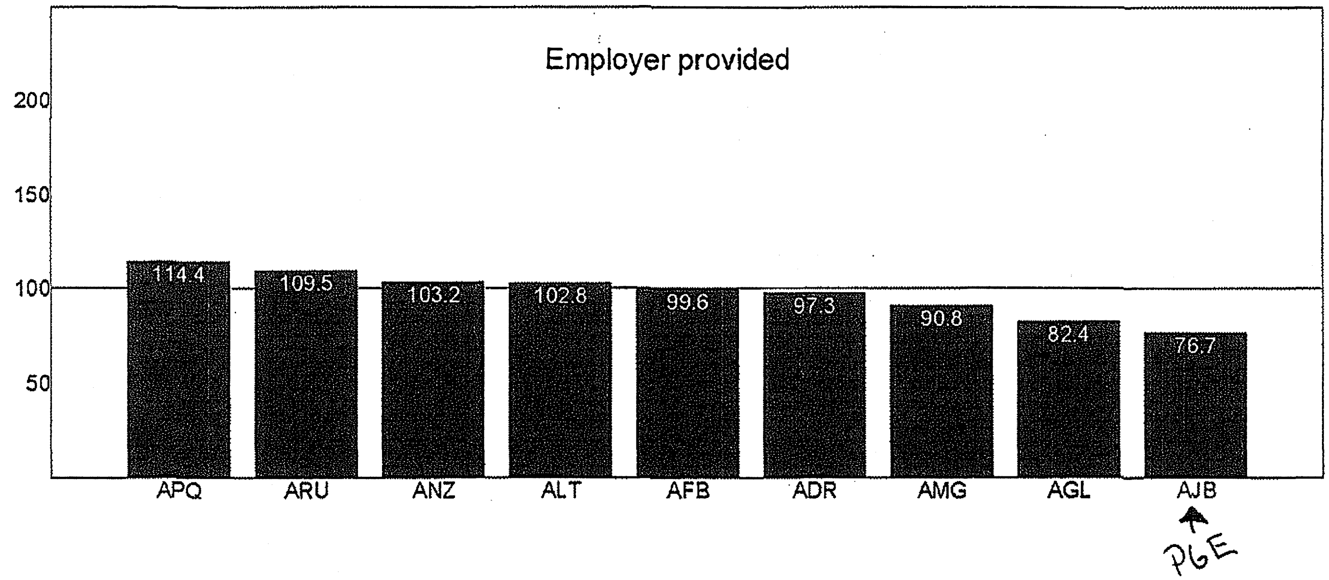
PGE Exhibit	Description
501	2010-2014 FTEs
502	PGE 2007 Pension BENVAL Study
503C	Pension Balancing Account

DIVISION	CLASS	DEPT	REG/ TEMP	2010 FTE Actuals	2011 FTE Actuals	2012 YTD SEPT FTE Actuals	2013 FTE Budget	2014 FTE Forecast	FTE Delta 2014-2011	Annual % Delta 2011-2014
A&G - Information Technology Total				266.0	251.2	255.6	250.1	250.1	(1.1)	-0.1%
ADMINISTRATIVE AND GENERAL Total				374.5	378.7	362.9	364.8	372.2	(6.5)	-0.6%
CUSTOMER ACCOUNTS Total				307.9	312.4	312.3	327.3	334.4	22.0	2.3%
CUSTOMER SERVICE Total				102.2	97.1	100.1	95.4	101.6	4.5	1.5%
GENERATING - BEAVER Total				52.9	53.7	55.9	56.2	58.6	4.9	2.9%
GENERATING - BIGLOW Total				6.0	6.5	7.4	8.0	9.0	2.5	11.4%
GENERATING - BOARDMAN Total				71.6	71.2	73.6	77.5	80.7	9.5	4.3%
GENERATING - COYOTE Total				15.0	16.5	17.9	14.9	14.9	(1.7)	-3.5%
GENERATING - OTHER Total				265.0	272.1	284.9	305.1	316.8	44.7	5.2%
GENERATING - PORT WESTWARD Total				20.4	20.9	21.2	23.4	23.4	2.5	3.8%
GENERATING - TROJAN Total				11.5	11.5	11.9	11.5	11.5	0.0	0.0%
TRANSMISSION & DISTRIBUTION Total				1,099.1	1,051.8	1,015.3	1,032.5	1,033.5	(18.3)	-0.6%
Grand Total				2,592.0	2,543.5	2,519.0	2,566.6	2,606.6	63.1	0.8%

Adjusted Totals by Division

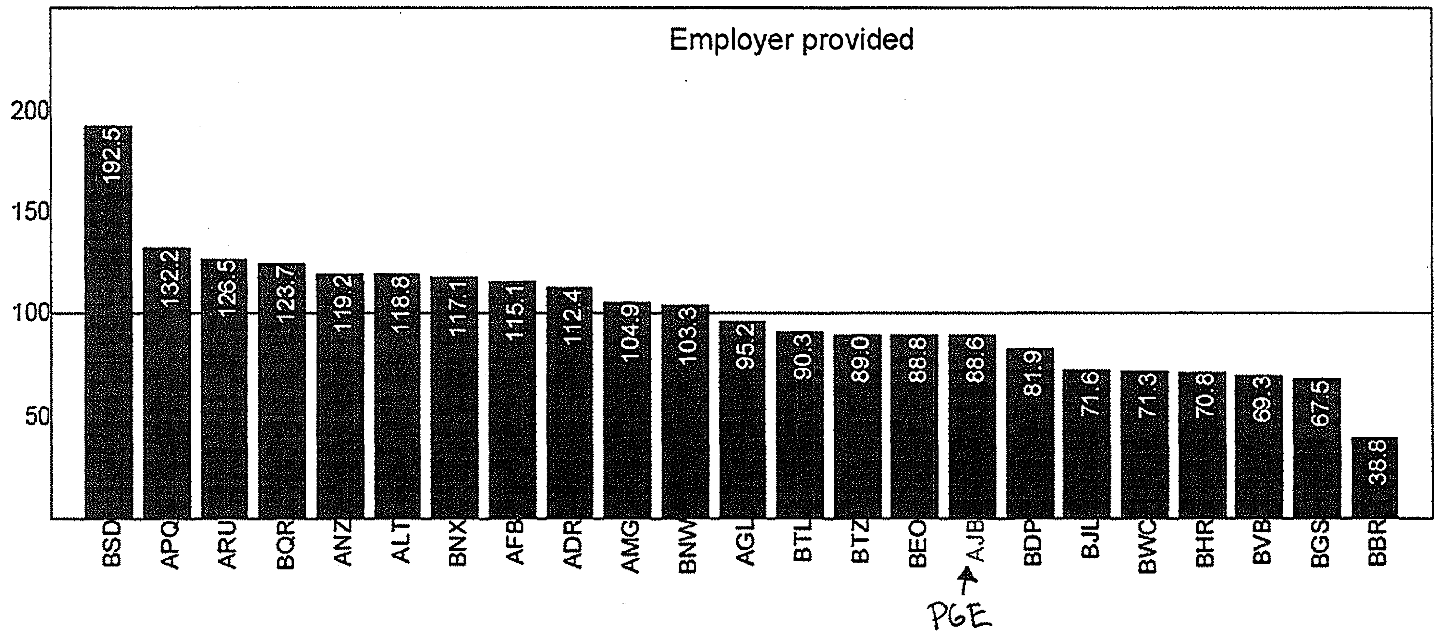
IT	266.0	251.2	255.6	250.1	250.1	(1.1)	-0.1%
Unfilled Position Adjustment				(5.7)	(6.7)		
Adjusted IT Totals	**266.0**	**251.2**	**255.6**	**244.4**	**243.4**	**(7.8)**	**-1.0%**
A&G	374.5	378.7	362.9	364.8	372.2	(6.5)	-0.6%
Unfilled Position Adjustment				(10.2)	(10.6)		
Adjusted A&G Totals	**374.5**	**378.7**	**362.9**	**354.7**	**361.6**	**(17.1)**	**-1.5%**
Adjusted A&G/IT Totals	**640.4**	**629.9**	**618.4**	**599.1**	**605.0**	**(24.9)**	**-1.3%**
Customer Accounting	307.9	312.4	312.3	327.3	334.4	22.0	2.3%
Unfilled Position Adjustment				(7.4)	(8.7)		
2014 Customer Accounting Adjustment					(2.0)		
Adjusted Customer Accounting Totals	**307.9**	**312.4**	**312.3**	**319.9**	**323.6**	**11.3**	**1.2%**
Customer Service	102.2	97.1	100.1	95.4	101.6	4.5	1.5%
Unfilled Position Adjustment				(2.1)	(2.5)		
Adjusted Customer Service Totals	**102.2**	**97.1**	**100.1**	**93.3**	**99.1**	**2.0**	**0.7%**
Adjusted Customer Accounting/Service Total	**410.1**	**409.4**	**412.4**	**413.2**	**422.7**	**13.3**	**1.1%**
T&D	1,099.1	1,051.8	1,015.3	1,032.5	1,033.5	(18.3)	-0.6%
Unfilled Position Adjustment				(13.5)	(15.8)		
2014 T&D Adjustment				(3.0)	(3.0)		
Adjusted T&D Totals	**1,099.1**	**1,051.8**	**1,015.3**	**1,016.0**	**1,014.7**	**(37.1)**	**-1.2%**
Generation	442.4	452.4	472.9	496.5	514.9	62.4	4.4%
Unfilled Position Adjustment				(19.4)	(12.0)		
2013-2014 Generation Adjustments	0.0	0.0	0.0	(6.1)	(19.6)		
Adjusted Generation Total	**442.4**	**452.4**	**472.9**	**471.0**	**483.3**	**30.8**	**2.2%**
Grand Total	2,592.0	2,543.5	2,519.0	2,566.6	2,606.6	63.1	0.8%
Unfilled Position Adjustment				(58.3)	(56.3)		
2013-2014 Generation Adjustments				(9.1)	(24.6)		
Adjusted Grand Total	**2,592.0**	**2,543.5**	**2,519.0**	**2,499.3**	**2,525.7**	**(17.9)**	**-0.2%**

PGE 2007 BENVAL – Revenue Group A, DB Pension Only



Excludes 5 organizations with no DB pension plan

PGE 2007 BENVAL – Revenue Group A & B, DB Pension Only



Excludes 8 organizations with no DB pension plan

Exhibit 503C

Confidential

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 262

Information Technology

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Cam Henderson
Behzad Hosseini

February 15, 2013

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I. Introduction

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

A. My name is Cam Henderson. I am the Vice President of Information Technology (IT) and Chief Information Officer at PGE.

My name is Behzad Hosseini. I am the Director of IT Strategy and 2020 Vision. Our qualifications appear in Section V of this testimony.

Q. What is the purpose of your testimony?

A. Our testimony is intended to provide an overview of IT initiatives at PGE that are relevant to this filing and to explain why these initiatives are directly related to the company's mission of delivering safe, reliable electric power to customers, with excellent customer service, while meeting all appropriate regulatory standards. Although many IT systems are invisible to customers, these systems and supporting processes are essential to our ability to meet customer expectations – including their expectation that we will offer services and features that make it easy for them to do business with us, that we will secure our systems to meet regulatory requirements, and that we will operate efficiently and effectively. In today's environment, IT forms a key component of our business infrastructure, and improvement of our business (in keeping with our strategic direction) requires improvement of our IT foundation. This will help us achieve near-term benefits and lay the groundwork for future service and efficiency and continued effectiveness.

Q. What activities or functions are you including as IT?

A. IT consists of the PGE departments responsible for developing, operating, and maintaining our computer, cyber, information, and communication systems. We note that these systems are becoming increasingly important to all aspects of PGE's operations (with increasing scope, reliance, and uses). In addition, the security of these systems is becoming more critical. As a result, the necessity for IT resources continues to increase.

Q. How much do you expect IT operations and maintenance (O&M) costs[1] to increase by the 2014 test year?

A. From 2011 to 2014, we forecast that IT costs will increase from $53.6 million to $64.1 million. Because these costs relate to all areas of PGE's operations, they are charged or allocated to appropriate areas and appear as part of each area's O&M costs. Since the majority of those costs relate to corporate systems, whose costs are allocated rather than charged directly to the operating areas, we discuss IT as a whole in this testimony.

Q. How is your testimony organized?

A. In the next section, we provide an update of PGE's progress in implementing its 2020 Vision program. We then provide detail regarding the IT department's O&M cost increases from 2011 to 2014. Next, we describe the O&M reductions achieved during this period, which partially offset the cost increases. The final section provides our qualifications.

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[1] Unless specifically indicated as capital costs, all costs in this testimony refer to O&M costs.

II. 2020 Vision Update

Q. In PGE's previous general rate case (UE 215) you introduced 2020 Vision as a major capital program to replace IT systems. Would you please provide a brief summary of the program?

A. In UE 215, specifically PGE Exhibit 600, Section IV, Part B, we described 2020 Vision as a 10-year strategy to "implement a set of projects that collectively modernize and consolidate our technology infrastructure. The ultimate purpose of this program … is to replace a multitude of existing software applications with fewer 'enterprise' applications that provide integrated functionality for PGE's operations."

Q. How did the IT environment change to make 2020 Vision practical?

A. As we noted in UE 215, "the critical factor is that enterprise or system-wide applications have matured in the last few years to where it is now practical to implement them. Integrated solutions are now available from leading software vendors, which are focused specifically on the utility industry and support end-to-end, industry-standard processes."

Q. What are the primary goals of 2020 Vision and have they changed since UE 215?

A. PGE has not changed the program's goal, which continues to be to implement common systems and standardized business processes throughout the enterprise to achieve efficiency and cost effectiveness. The program's primary objective is to replace obsolete technologies. Additional objectives include:

- Support a safe and reliable power delivery system;
- Gain operational efficiencies through business process improvement;
- Meet customer and PGE needs for accurate and "real-time" information;
- Reduce the number of applications and reduce the number of vendor relationships;

- Integrate data across applications (reduce redundancy and inconsistencies); and
- Maximize the potential of Smart Grid technology.

Q. Have you updated your planning or strategy for 2020 Vision since UE 215?

A. Yes. In UE 215, we introduced 2020 Vision as a three-phase program with ten distinct sub-projects (reproduced here as PGE Exhibit 602). In 2011, we identified process improvements that are necessary to achieve greater system benefits from the software and hardware implementation projects. Consequently, we re-evaluated the program and established a 2020 Vision roadmap, which identified the full scope of activities associated with the program (see PGE Exhibit 603). This effort involved close coordination with PGE's benchmarking efforts to identify areas with specific requirements plus a comprehensive review of all applicable business process designs.

Q. What 2020 Vision projects has PGE successfully implemented to date and what were their capital costs?

A. From 2010 through 2012, PGE completed the implementation of the first set of 2020 Vision projects:

- Work Management System (WMS) upgrade, $0.2 million – To upgrade Distribution's legacy work management system to ensure continued vendor support and compatibility with other PGE systems until that system is replaced in 2015.
- Finance and Supply Chain Replacement Project (FSRP), $26.5 million – To replace PGE's 26-year old financial system, which was no longer supported by the vendor, along with associated applications (e.g., spreadsheets, custom developed programs, etc.). We also reduced the number of financial

systems by eight and integrated the new system with other applications. PGE Exhibit 1000 provides additional detail on this project.

- Infrastructure (hardware) and program office, $7.7 million – Represents hardware costs and project management for 2020 Vision.
- Maximo, Mobile and Scheduling Wave 1, $36.4 million – Modernizes and consolidates PGE's mobile and scheduling tools into a single application and standardized hardware. This system enables consistent and comprehensive tracking of work and assets, plus it is integrated with other work systems to be used in scheduling, dispatching, and updating field work. Wave 1 is used primarily by generation and substation operations as well as individual field personnel (as opposed to crews) within transmission and distribution (T&D). PGE Exhibit 800 provides additional detail on this project.
- Maximo for IT, $1.7 million – Replaces PGE's previous IT work management system, which is no longer compliant with our security policies. Maximo for IT supports our new, metric-based IT Service Management processes and provides a common asset data base across PGE.

Q. What 2020 Vision projects have you forecasted to close from 2013 through 2015 and what are their estimated capital costs?

A. We expect to close the following:

- "myTime" Time Collection System, $7.7 million estimated and expected to close in 2013 – A web-based solution that captures time and labor data and automates complex rules, regulations, and union contract provisions regarding pay. myTime will also automate "leaves management" processes as well as account for contingent workers to improve compliance tracking and streamline procure-to-pay processes. PGE Exhibit 1000 provides additional detail on this project.

- Maximo, Mobile and Scheduling Wave 2, $39.0 million estimated and expected to close in 2015 – To add functionality for T&D operations plus additional users (e.g., line crews and joint-use employees). PGE Exhibit 800 provides additional detail on this and the following two projects.
- Outage Management System, $18.2 million estimated and expected to close in 2015 – To replace PGE's in-house developed application with a modern, vendor-supported application that will improve response time, crew efficiency, and outage information.
- Geographic Information System (GIS) and Graphic Work Design (GWD), $22.1 million estimated and expected to close in 2015 – The new GIS system will improve the accuracy of PGE's asset location data, provide field employees with interactive access to asset information, and enable PGE to share critical information with emergency response and public officials. GWD will provide mobile field design capabilities that will reduce manual/paper-based work processes and reduce design time for non-complex, customer-requested jobs.

Q. Are the benefits of these projects realized in the IT department?

A. In some instances, yes. For example, with Maximo for IT, we can better manage our hardware and software assets, thus reducing maintenance costs. Primarily, though, most benefits are realized by the operating area in which the systems are deployed. For example, the FSRP's benefits are being realized mostly in PGE's Accounting and Tax departments (see PGE Exhibit 1000 for details on these operational benefits). Benefits from the Maximo, Mobile and Scheduling project will be realized in Distribution operations. PGE Exhibit 800 provides details on these operational benefits.

Q. What additional 2020 Vision projects are you currently developing for future implementation?

A. In 2013, we plan to begin work to replace the current Customer Information System and Meter Data Management System. These efforts are part of a larger Customer Engagement Transformation (CET) program that also includes customer program automation. PGE Exhibit 900 provides additional discussion of CET.

Q. Are any of the capital projects that you identify as closing after 2014 included in the 2014 test year revenue requirement?

A. No. They are not included in PGE's 2014 average rate base.

III. O&M Costs

A. Summary

Q. Have O&M costs increased because of the 2020 Vision activities?

A. No. The overall IT department's costs increase is driven by three primary areas, which we discuss below: 1) critical infrastructure protection; 2) maintenance agreements on software and hardware; and 3) labor loadings on allocated IT costs.

Q. In Section I, you stated that IT's O&M costs have increased by approximately $10.5 million from 2011 actuals to the 2014 forecast. What are the components of that increase?

A. The following table shows the categories of total IT costs and identifies the components that account for the forecasted $10.5 million increase:

Table 1
Total IT Costs ($ Millions)*

Category	2011 Actuals	2014 Test Year	Variance 2011 - 2014
Direct Charges to Operating Areas	$14.4	$13.6	($0.8)
Allocated Charges to Operating Areas	29.1	38.0	8.9
Labor Adjustment	0.0	(0.9)	(0.9)
Subtotal IT Charges	43.5	50.7	7.1
Labor Loadings Charged to Operating Areas	9.7	12.8	3.1
Corp Governance Allocation to Operating Areas	0.3	0.6	0.3
Total IT	**$53.6**	**$64.1**	**$10.5**

* May not sum due to rounding.

Q. Please explain how IT costs are charged to the specific functional areas.

A. As seen in Table 1 above, PGE's IT costs consist of three categories: directly charged (or assigned), allocated, and labor loadings/corporate governance allocation. Directly charged costs relate to systems that apply to specific operating areas, such as production, transmission, or distribution. These costs are charged directly to specific expense accounts related to those operations. Other IT work in the areas of voice, data, network, communications, business recovery, the data center, and office systems are not directly related to one specific operating area. Instead, these costs apply broadly to all PGE activities and departments and are first charged to a balance sheet account and then allocated to the expense accounts of the various functional areas. Labor charged to the balance sheet has associated labor loadings and a corporate governance allocation applied per PGE's loading and allocation policies, which are submitted annually to the OPUC Staff as an attachment to our Affiliated Interest Report. A summary of IT charges to each operating area by direct charge and allocation is provided as PGE Exhibit 601.

Q. What do the labor loadings and corporate governance allocations represent?

A. The labor loadings represent payroll-related costs that are first charged to Administrative and General (A&G – e.g., benefits and employee support) and payroll taxes, and then applied to O&M accounts, based on specific rates per allocated IT labor. Ultimately, the costs represented by these loadings begin in O&M and end in O&M so they are not specifically IT costs; rather they are labor-related costs that follow allocated IT costs. Consequently, these costs are discussed in PGE Exhibit 500, which addresses labor-related costs as part of total compensation.

The corporate governance allocation is similar to loadings in that the costs are first charged to A&G and then applied to O&M accounts, based on specific rates per allocated IT labor. As with loadings, they are not specifically IT costs, rather they are A&G costs that follow allocated IT labor costs. A&G costs are discussed in PGE Exhibit 1000.

Q. Why do the loadings increase by $3.1 million?

A. The loadings are projected to increase because the underlying costs are increasing from 2011 to 2014, with pension costs accounting for the majority of the increase.

Q. Please explain the labor adjustment.

A. As discussed in PGE Exhibit 500, PGE applied two labor adjustments in its 2014 forecast. The first is a ($5.0) million labor adjustment to reflect (56.3) open full time equivalent (FTE) positions in the test year forecast. The allocated IT portion of this adjustment is approximately ($0.7) million and (6.7) FTEs. The change in FTEs is summarized in Table 2, below.

Table 2
Total IT FTEs*

Category	2011 Actuals	2014 Test Year	Variance 2011 - 2014
Unadjusted FTEs	251.2	250.1	(1.0)
Labor Adjustment	0.0	(6.7)	(6.7)
Adjusted IT FTEs	**251.2**	**243.4**	**(7.8)**

* May not sum due to rounding.

Q. What is the second labor adjustment?

A. The second adjustment is for ($1.0) million and is related to efficiencies we expect to realize from the myTime project discussed above. The IT component of this adjustment is ($0.2) million. PGE Exhibit 1000 provides further details regarding myTime.

B. Incremental and Offsetting IT Costs

1. Critical Infrastructure Protection Version 5

Q. You stated previously that aside from labor loading effects, one driver of IT's O&M cost increase from 2011 to 2014 is critical infrastructure protection requirements. Can you please describe this in more detail?

A. Yes. "CIP Version 5" is a set of Reliability Standards developed by the North American Electric Reliability Corporation (NERC). These Critical Infrastructure Protection (CIP) standards, CIP-002-5 through CIP-011-5, provide a cyber security framework for the identification and protection of the Cyber Systems that support reliable operation of the Bulk Electric System (BES). Version 5 of these standards was developed to address any remaining requirements that the Federal Energy Regulatory Commission (FERC) imposed in 2008 in Order No. 706 that were not addressed in Version 2 through Version 4.

Q. How does Version 5 differ from previous CIP standards?

A. Version 5 represents a fundamental shift from earlier versions of the CIP standards. In earlier versions, each entity first identified those assets that were critical to the operation of the BES, and then focused on protecting only those Critical Cyber Assets deemed essential to the operation of the Critical Assets. By contrast, in Version 5, entities are required to identify all Cyber Assets that could cause a disturbance to the BES if they were misused or destroyed. The entity must then categorize each such BES Cyber Asset as "High," "Medium," or "Low" according to specific bright-line criteria.

In addition, certain cyber assets that were previously out-of-scope because of their specific communications protocol are now in-scope for Version 5. The result is a much larger set of cyber assets in the scope of the CIP standards than in previous versions.

In addition to the larger scope of assets that require both electronic and physical protection, there are other important changes in Version 5 of the standards:

- Entities will need to provide more specialized training to anyone with access to BES Cyber Assets;

- Entities will need to more rigorously track who is authorized to access these assets and to terminate this access more quickly when it is no longer needed;
- Entities will need to strengthen the management of how their BES Cyber Assets are initially configured, how changes to those assets are managed, and how the vulnerability of those assets is assessed; and
- Entities will be required to conduct more thorough monitoring of their compliance with the CIP requirements, including developing a monitoring program for each of 17 requirements.

Q. How does PGE plan to meet these requirements?

A. PGE is planning to address these new requirements with one centrally-managed project that has many different components. PGE expects that the increased scope of Version 5 will place significant additional documentation burdens on each operating unit that is impacted by the regulations. In addition, PGE's preliminary estimate is that there will be significant additional costs in several operating units as follows:

- Administration – Corporate Security will incur additional costs associated with developing a more rigorous process for granting and revoking physical access to meet enhanced requirements. Corporate Security will also need to implement an enhanced alarm notification process that includes logging and analysis of a wider range of events. Corporate Training will incur costs to help PGE meet more rigorous training requirements. Additional costs are associated with tracking a larger asset base and more documentation requirements.

- Distribution – Both the System Protection and the Transmission and Distribution groups will see a significant increase in the assets that need to be protected. The costs are associated with increased maintenance and documentation requirements.
- Finance – In order to successfully manage the implementation of these complex regulations, Project Management will need to be centralized.
- FERC Compliance – The FERC Compliance Department, under the Vice President, General Counsel, and Chief FERC Compliance Officer, will incur additional costs to develop and maintain the increased number of training modules needed for compliance. The FERC Compliance Department will also be responsible for management of the Information Protection Program.
- Generation – Both the generating plants and the Power Supply Engineering Services Department will incur additional costs related to third-party assessment of control systems and development of updated procedures.
- Information Technology – The IT group will bear the majority of CIP Version 5 costs. These are associated with the increase in the number of assets in scope that will need to be supported by that group. In addition, more rigor around review of event logs, management of configuration changes, and control of physical and logical access will require significant configuration changes, including automation of processes that are currently performed manually. The increased number of assets and increased rigor of requirements will compel PGE to revisit and possibly strengthen its approach to maintaining a separate Energy Network (EN) as discussed below. Finally, IT will need to invest in tools to automate some of the new requirements.

Q. What is the current status of CIP Version 5?

A. The NERC Standard Development Process includes multiple rounds of standard rewrites and industry balloting. The most recent round of balloting closed on November 5, 2012. In that balloting, Draft 4 of each standard CIP-002-5 through CIP-011-1 was approved by a significant margin. Version 5 was approved by the NERC Board of Trustees on November 26, 2012, and NERC filed these standards for FERC approval on January 31, 2013. The current proposed effective date for all but one requirement of Version 5 is the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the FERC order approving the standards. Therefore, if FERC approves these standards in the second quarter of 2013, they would be effective July 1, 2015. FERC could approve the standards with no changes, or make the standards effective while directing NERC to make changes in a subsequent version of the standards, or decline to approve the standards; however, under the Energy Policy Act of 2005, FERC does not have the authority to revise the standards or to write their own CIP standards.

Q. Why are you forecasting costs in 2014, if the standards will likely not go into effect until 2015?

A. An effective date of July 1, 2015, means that entities such as PGE must be fully compliant with the new standards on that date. The complexity of the activities required under the new standards and the large increase in the scope of equipment covered by these standards necessitate a lead time of longer than six months. PGE will need to undertake activities in 2014 to design, build, test, and begin to implement the new processes, procedures, controls and systems enhancements to become compliant by the effective date. If FERC approves the CIP Version 5 standards and PGE is not fully compliant by the effective date, PGE would incur a violation that would be subject to financial penalties. FERC has the legal authority to penalize PGE as much as $1 million per violation per day.

Q. What will you do if FERC does not approve CIP Version 5?

A. The 2014 forecast includes an estimated $5.2 million of incremental costs for complying with Version 5 as currently written (i.e., $3.8 million in IT and $1.4 million in other operating areas, particularly A&G). If FERC does not approve these standards as written, PGE will continue with its efforts to comply with the currently effective Version 3 and Version 4 of the standard and we will adjust the test year forecast to correspond to the effective standards.

2. Maintenance Agreements on Software and Hardware

Q. Please explain the other driver of IT's O&M cost increase from 2011 to 2014, which is an increase in hardware and software maintenance agreements.

A. O&M costs for maintenance agreements on hardware and software tend to increase every year because of:

- Simple cost escalation;
- Implementing new systems to meet new or changing requirements; and
- Replacing obsolete systems with newer systems that are more complex and have greater functionality than the old system, e.g., PGE's financial system replacement as mentioned above. In such instances the new systems can increase efficiency by eliminating certain manual processes and/or by meeting new requirements that the old system could not address.

In other words, increases in the IT operational budget are indicative of, and appropriate to, the purchasing of new technologies or expanding the usage of existing technologies.

Q. Why is software and hardware maintenance necessary?

A. The technologies must be maintained to: 1) keep them operational and/or compliant by retaining appropriate licenses; and 2) receive regular upgrades to correct programming errors and provide continued technical maturity.

Q. If 2020 Vision is intended to replace numerous applications with fewer enterprise systems, why would PGE's maintenance costs increase?

A. As we decrease the number of applications through consolidation, we see an increase in the maintenance cost associated with either new replacement applications or expanded use of existing applications (which is especially pronounced, as we replace home-grown software, which requires no maintenance charge). In short, some of the applications we are consolidating have a lower maintenance cost associated with them than the replacement technology. We expect, however, the new applications to create benefits in other departments of PGE.

Q. What other reasons account for the increase in software and hardware maintenance costs?

A. Another aspect results from PGE implementing new technologies to support changing business needs, expanding regulatory requirements, or improvements in the business that require supporting technologies that we do not currently have in place. In an effort to mitigate this dynamic, PGE has a plan to systematically review and eliminate unneeded software. In addition, we review our existing portfolio of technologies and compare the portfolio to new business needs to help ensure we are not duplicating capabilities to meet those requirements.

Q. What are some examples of the new IT maintenance agreements?

A. Four of the largest examples are Maximo (described as part of the 2020 Vision program, above), cyber security, new IT infrastructure for the Readiness Center, and new phone technology (i.e., voice over internet protocol - VoIP).

Q. Please describe the cyber security project.

A. PGE has implemented a cyber security roadmap to reduce our security and data risk while building our security capability and architecture to a level that is consistent with both current industry practices and regulatory requirements. The primary implementation of this project began in 2010 and will continue through 2015.

Q. Why have you implemented this project?

A. PGE employed Ernst & Young LLP in 2008 to perform a data security assessment, which indicated that our cyber security risk exposure could be improved. In addition, based on cyber threats to the national infrastructure, there is a significant federal push to bring the utility industry as a whole into a security model similar to that of banking institutions and other industries considered to be "high risk." Consequently, PGE faces significantly increasing regulatory requirements and guidelines provided by NERC, FERC, the Department of Homeland Security, Sarbanes-Oxley, and the OPUC to address the growing number of threats and vulnerabilities such as viruses, worms, hacker sophistication, and potential terrorist activities.

By deferring this project, PGE would be subject to an increasing risk of data breaches, data loss, or compromised operations by hackers who could exploit vulnerabilities in PGE's cyber assets. We would also face financial penalties due to non-compliance with legal and regulatory requirements. In short, neither PGE nor its customers can afford to defer this work.

Q. What is PGE currently implementing as part of the cyber security roadmap?

A. PGE is currently implementing the Network Segmentation, Desktop Application Control, and Data Loss Protection projects. The Network Segmentation project involves gathering business requirements and using them to restructure PGE's current network architecture (i.e., the network that ties together all of PGE's computers). This restructuring will separate the production business network from test, development, and training segments of the network. PGE has already separated its Energy Network (generation, transmission and distribution services) from its business systems (e.g., human resources, finance). These changes will increase the security of company data and ensure that applicable IT resources can be safely accessed by appropriate vendors and other outside entities in a secure fashion. Network segmentation is promoted by the National Institute of Standards and Technology (NIST) Smart Grid Conceptual Framework model.

The Desktop Application Control project involves implementing new controls on employee desktop computers while upgrading PGE desktop and laptop computers to Windows 7. These controls increase PGE's control of the desktop environment and distribution of applications. By creating a controlled and secured process for access to applications, PGE increases security and software licensing compliance.

The Data Loss Protection project uses PGE's ability to identify and tag critical or sensitive data and protect it from disclosure by utilizing recent technology investments. The tagging of sensitive data will allow users to proactively identify sensitive data when it is created and then PGE encryption systems will be configured to encrypt or protect as needed. Additional functionality will include the ability to encrypt laptops, external hard drives, and remotely wipe devices that are lost or stolen.

Q. What are the capital costs associated with the cyber security roadmap?

A. Total capital costs through 2015 period are estimated to be approximately $20.3 million, with $2.8 million in service at year-end 2012.

Q. Are PGE's cyber-security-related efforts complete in 2015?

A. No. Beyond 2015, PGE will address emerging issues and compliance requirements as they arise.

Q. What is the Readiness Center?

A. The Readiness Center is a new PGE facility that will become operational in late 2013, with a capital cost of approximately $22.5 million: $13.5 million for the building and $9 million for the IT infrastructure. The center will house IT infrastructure and equipment that will be used to meet our contingency obligations under federal regulations[2] such as networks, servers, storage and communications systems in an approximately 18,000-square foot building. The Readiness Center is designed to provide critical response and recovery functions to maintain public safety, control electric transmission and distribution, and restore power in the event of a catastrophic emergency that renders primary critical response and recovery functions inoperable. The primary critical response and recovery functions are currently located in the World Trade Center (WTC).

The Readiness Center will be a seismically engineered back-up facility designed to remain operational during and after extreme environmental events. It will combine back-up critical/essential business functions that rely heavily on IT infrastructure.

Q. Why is the Readiness Center necessary?

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[2] See the mandatory NERC Reliability Standard EOP-008-0, "Plans for Loss of Control Center Functionality," which requires PGE as a Transmission Operator and Balancing Authority to have a plan to continue reliability operations in the event that its control center becomes inoperative. EOP-008-1, which will replace EOP-008-0 in July 2013, contains even more specific requirements for backup functionality. In addition, mandatory NERC Critical Infrastructure Protection Standard CIP-009-3 governs PGE's recovery plans for Critical Cyber Assets.

A. It is necessary for several reasons:

- A 2008 study by KPMG LLC, identified the Critical/Essential business functions currently at PGE's Portland Service Center (PSC) as "at risk" in the event of a disaster.
- PSC's proximity to the World Trade Center increases the likelihood of common mode failures, wherein both facilities are affected by the same catastrophic event.
- PSC's back-up Data Center is anticipated to reach maximum capacity by 2014.
- A TriMet Light Rail Line will pass exceedingly close to the PSC and will consequently introduce additional operational risk in 2014.

Q. Is the implementation of a back-up data center a standard utility approach?

A. Yes. Implementation of off-site, back-up data centers within utility service territories is a common approach to mitigate risks of primary data center loss.

Q. Does the Readiness Center provide any additional benefits?

A. Yes. The Readiness Center will serve as a secondary data center as well as a more reliable back-up site. Whereas PSC was only intended to be used in event of emergency, the Readiness Center will be able to share IT processing with WTC equipment. This means that the Readiness Center will perform regular IT operations, which will serve to minimize the risk of IT disruption at the WTC.

Q. What is the voice over internet protocol (VoIP)?

A. VoIP will upgrade our existing voice or telephone network because most of that system is over 15 years old and is no longer supported by the manufacturer. VoIP refers to the way in which the new voice communication systems use the existing data network (i.e., the same network to which PCs are connected), for the purposes of transmitting voice conversations internally and externally. This project will replace the existing Nortel system with a Cisco Communication and Collaboration system to provide integrated voice and voicemail services, video communications, instant messaging, collaboration services such as WebEx, as well as Contact Center services in support of business requirements.

3. Cost Mitigation Efforts

Q. What measures are you implementing to reduce costs?

A. PGE's IT Vision Design Project identifies opportunities for improvement, cost savings, performance management, efficiency and other initiatives that will enable the IT Department to help PGE achieve its strategic direction goals of operational excellence and outstanding customer service. This will be a multi-year effort involving significant change in individual and management performance as well as leveraging various opportunities to reduce IT costs. We expect that IT Vision Design will define an operating model for IT to meet anticipated levels of efficiency and effectiveness. PGE Exhibit 604 describes the IT Vision Design roadmap. IT Vision Design's multiyear goals, with a projected target completion of 2015, are defined as follows:

1. A top third rating on an industry-recognized model that measures the current state of capabilities of IT processes (i.e., the Capability Maturity Model scale).
2. A second quartile operating efficiency when compared to other mid-sized investor owned utilities.

Q. How will IT Vision Design move IT toward this level of performance?

A. Through benchmarking, outside consultants, and review of peers, PGE shaped the IT Vision Design strategy around six foundational principles defined as the following:

- Partner With the Business – The integration of Business and Technology requires a strong partnership between IT and the business. IT will effectively coordinate with our business partners and proactively work to deliver solutions aligned to business objectives.
- Eliminate Complexity – The IT department spends approximately 45% of its budget on O&M. By reducing the complexity of the technology environment, IT can reduce the basic cost of running the business and focus on meeting new business needs.
- Source Strategically – The IT Department will provide a high level of service at a cost-effective price. Because local resources do not always present the best value to PGE and our customers, IT needs to manage costs by employing the most cost-effective resources, regardless of their location.
- Standardize IT Process/Procedures – IT procedures have evolved over time and occasionally have been optimized for one subset of the department, which has potentially reduced overall department efficiency. IT will standardize and streamline key processes and procedures to increase operational efficiency.
- Build a Strong Workforce – IT will carefully manage workforce performance by developing clear position definitions and expectations, and then holding the workforce accountable to these expectations. IT will also implement common strategies for training and workforce development to address the skills needed for our changing technology.
- Meet Increasing Service Expectations – IT and the various PGE business units will mutually identify service level expectations. IT will measure service delivery to ensure service expectations are being met and engage in corrective procedures where

service levels are missed. IT will monitor client satisfaction to ensure that clients are satisfied with services received.

Q. How is PGE implementing these principles?

A. They are the basis for 15 improvement initiatives to be completed over the next three years. In 2013, IT will focus on the following six initiatives:

1. Improve Workforce Management – To effectively manage the way IT attains skilled resources to meet business needs. This process involves two steps:
   - Effectively rate current IT personnel based on how they align to IT's expectations.
   - Identify gaps in existing skill sets and develop a plan to fill these needs through training or acquisition of skills from outside sources.
2. Improve Business Relationship Management – To optimize the efficiency of IT resources with business requirements, IT will provide an Account Executive function to each line of business. This will ensure that IT understands the business requirements and technology demands, and that they are in alignment with the IT Strategy. IT resources will then be prioritized based on overall business needs.
3. Improve Demand and Supply Management – To improve the process of prioritizing requests for IT services against limited IT resources. One expected outcome is improved management of IT discretionary time against service requests. To accomplish this, IT will invest in enhanced portfolio management capabilities to automate key process flows such as communication, demand requests, supply reconciliation, and variance reporting.

4. Simplify the Application Portfolio – To simplify the application environment by reducing the complexity of the application portfolio. This will be achieved by reducing redundant applications and sharing similar applications throughout PGE, where appropriate. As noted below, PGE eliminated 12 applications in 2012 and the goal is to eliminate another 33 applications in 2013. Our application portfolio simplification effort will directly reduce infrastructure demands, which will help reduce complexity in the infrastructure area as well.
5. Evaluate Application Support Outsourcing Opportunities – To pursue targeted outsourcing opportunities in the applications area to obtain required skills and increased capabilities at a reduced cost. Any outsourcing opportunities will require a business case to justify the cost and benefits and to identify the best alternative.
6. Initiative Oversight Program – Provide oversight and reporting on the progress of IT Vision Design initiatives to make sure the program is progressing appropriately. Another role will be to track and validate realized savings.

Q. How much do these initiatives cost?

A. PGE has not budgeted incremental costs for these initiatives in 2013 because they will be covered by efficiency gains elsewhere in IT. In 2014, there is also no incremental budget as we will pursue more initiatives only as additional savings become available.

Q. What savings will be attained through IT Vision Design?

A. There is an ever-increasing demand for technology in today's business environment as it brings potential to create business efficiencies. For example, the realized efficiencies in Finance and Accounting and Procurement through FSRP implementation are specified in Exhibit 1000 Section II Part A. Through IT Vision Design initiatives, IT will be able to continue addressing PGE's growing need for technical infrastructure and support while maintaining a relatively flat employee count. From 2011 through 2014, we project a net reduction of 7.8 FTEs for IT.

Q. How will IT's FTE reduction be achieved?

A. IT Vision Design will increase its focus on performance management in the near term with an aim of retaining skilled workers. The following practices will be implemented to assist with the reduction process initially:

- Voluntary early retirement packages for eligible employees;
- Redeployment of non-IT roles to the respective functional department; and
- Selective backfilling of vacant positions based on needed skills.

Q. Are there any other cost saving initiatives occurring in IT?

A. Yes. Listed below are other current initiatives that continue to lower costs and improve IT's overall efficiency:

- Through the use of agile methodology in our application development areas, IT has been able to eliminate time devoted to application support work. This is due to better planning and testing, improved quality of code, and improved change management processes. The reduced support time is then redeployed to higher-value IT jobs including maintenance and enhancement of system functionality. Maintenance work ensures more reliable systems, while functional enhancements allow PGE to pursue more value-added IT projects to further improve efficiency. Some examples of agile application initiatives are:

  - Monthly dashboard metrics tracking workload value, productivity, and project progress to move focus from low-priority, support work to high priority, high-value work.
  - Incremental release management enabling the release of IT solutions to end-users sooner to reduce unnecessary work and improve project time to value.
  - Increased frequency of testing of IT solutions through automation early in the build process as a form of preventative maintenance by reducing the potential costs of defects.

From 2010 through 2012, IT reduced support by approximately $464,000 for PGE labor and $276,000 for contract labor. From 2010 to 2014, we project that IT support labor costs will remain relatively flat and contract labor for support has been removed from the budget.

- PGE continues to leverage the use of virtual servers over physical servers. On a 1:1 basis, PGE has an avoided cost of at least $3.3 million since 2009 due to purchasing virtualized instead of physical servers when possible (PGE Exhibit 605 provides explanations of avoided costs benefit). Server virtualization also allows for more consistent deployment resulting in less human error. Further, virtualized server builds also take hours whereas physical server builds can take days. Because of the consistency, ease of build, and flexibility of virtualized servers, PGE's server administrators are now able to manage over twice the amount of servers with the same staffing.
- Contract management has continued to improve IT's ability to purchase and negotiate effectively, which saved PGE approximately $179,000 and $517,000 in 2011 and 2012, respectively. Beginning in 2012, by utilizing NPI, a third party

consultant, we examine and analyze industry purchase data on software and hardware purchases over $25,000; PGE uses this information to achieve consistent market contract administration. NPI services cost PGE approximately $200,000 annually; while PGE has realized over $517,000 in avoided costs in 2012. PGE has renewed its contract with NPI for 2013.

- PGE retired 12 applications in 2012, saving approximately $350,000 annually. In 2013, we plan to retire 33 more applications with over $200,000 in annual operating savings.

IV. Conclusion

Q. Please summarize your request for IT in this filing.

A. We request that the Commission approve PGE's forecast of $64.1 million in IT O&M costs in the 2014 test year ($50.7 million not including labor loadings and allocations). We also request that the Commission continue to approve PGE's investment in the 2020 Vision program and other capital projects as summarized in this testimony and as included in PGE's average rate base. Although we are proposing a $10.5 million increase in O&M since 2011 ($7.2 million not including labor loadings and allocations), this is driven by requirements for regulatory compliance and the need to maintain appropriate levels of software and hardware maintenance. To mitigate this increase, we have instituted a number of measures to reduce costs in the 2014 forecast and to enhance IT's efficiency and effectiveness on an on-going basis.

V. Qualifications

Q. Mr. Henderson, please provide your qualifications.

A. As vice president of PGE for Information Technology, I am responsible for the infrastructure, operations and system development of all information systems. This includes developing a strategic plan for information technology and implementing enhanced project management and methodology. I joined PGE in 2005 after serving as Chief Information Officer at Stockamp & Associates since 2003. Previously, I spent eight years as senior IT manager for Willamette Industries, Inc. and was named vice president and chief information officer in 1998. I received a bachelor's degree in management from Harding University in Searcy, Ark., and an MBA from the University of Texas. I am also a Certified Public Accountant in Oregon.

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

A. I earned a Bachelor degree in Finance and MBA from Portland State University, where I teach courses in Management, Finance, and Information Technology. I have also taught Management and Human Resources courses for the University of Phoenix and the Utility Management Certificate course for Willamette University. I currently work as the Director of Information Technology Strategy and 2020 Vision at PGE. Prior to this, I held leadership positions in the Human Resources, Organizational Development, Finance and Accounting, Business Decision Support, and Distribution departments at PGE. Additional experience includes retail sales management, restaurant management, as well as consulting work for a variety of clients.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
601	Summary of IT Costs by Operating Area
602	Copy of UE 215, PGE Exhibit 602 – Summary of 2020 Vision Capital Costs
603	2020 Vision Roadmap
604	IT Vision Design Initiatives
605	Virtual Server Avoided Costs

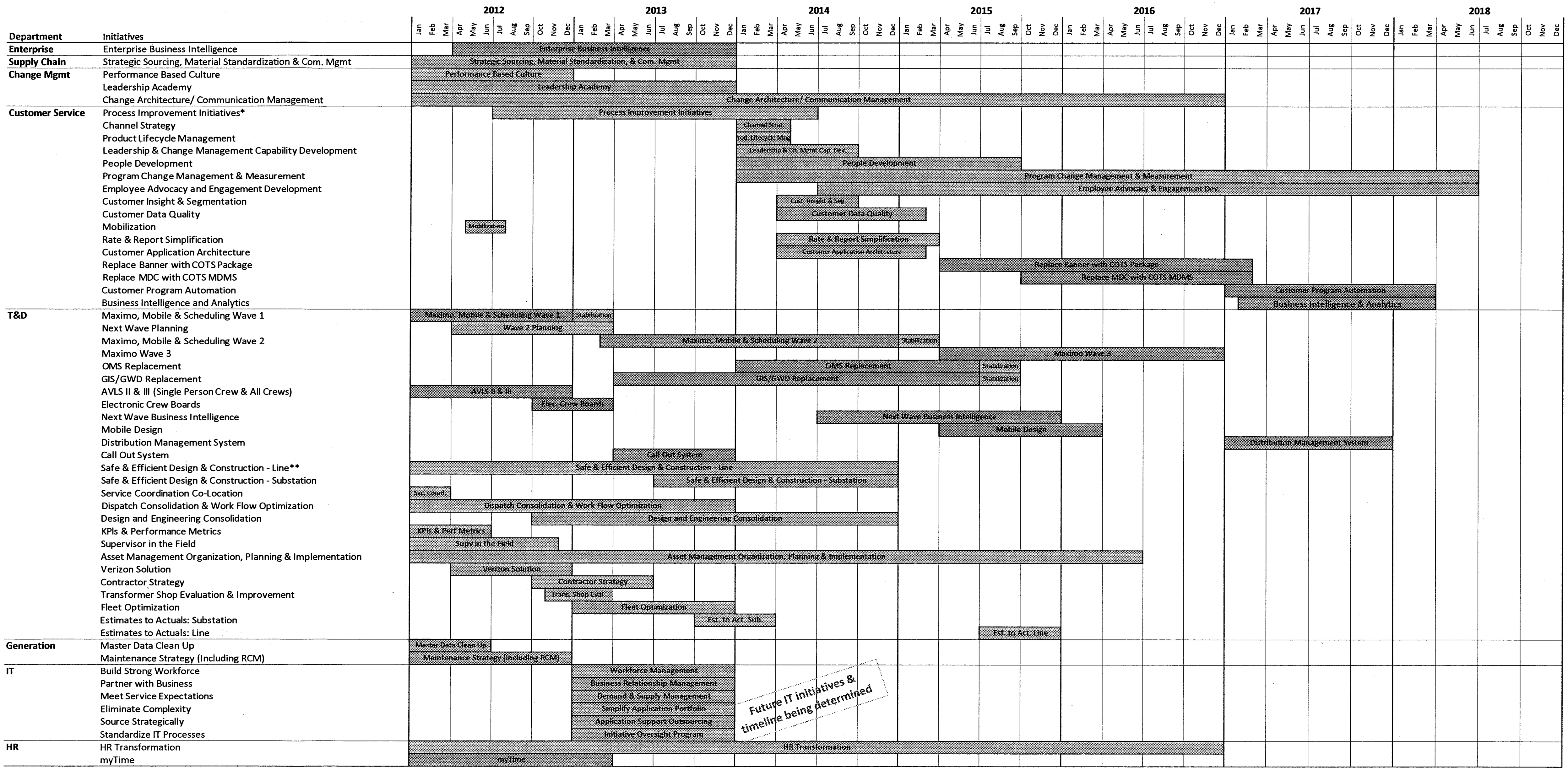
IT Summary by Operating Area

Funtion	2010 ACTUALS	2011 ACTUALS	2012 FCST (9+3)	2013 Budget	2014 Forecast	2014-2011 Delta	Annual % delta 2011-2014
Production							
Assigned	608,454	362,389	274,711	397,755	369,352	6,963	0.6%
Allocated	3,892,290	6,019,105	6,341,996	5,354,267	6,827,461	808,357	4.3%
Total Production	4,500,744	6,381,494	6,616,706	5,752,022	7,196,813	815,319	4.1%
Power Operations							
Assigned	764,101	635,983	708,941	705,434	731,799	95,817	4.8%
Allocated	780,153	1,590,556	1,933,524	1,812,958	2,131,283	540,728	10.2%
Total Power Ops	1,544,254	2,226,538	2,642,466	2,518,391	2,863,083	636,544	8.7%
Transmission							
Assigned	960,033	579,676	440,083	579,541	601,281	21,605	1.2%
Allocated	462,973	643,982	691,227	1,135,628	1,451,376	807,394	31.1%
Total Transmission	1,423,006	1,223,658	1,131,310	1,715,169	2,052,657	828,999	18.8%
Distribution							
Assigned	1,373,265	1,951,077	341,855	984,200	1,623,153	(327,925)	-5.9%
Allocated	9,688,338	14,572,652	15,682,485	13,263,671	16,916,286	2,343,634	5.1%
Total Distribution	11,061,603	16,523,729	16,024,340	14,247,871	18,539,439	2,015,710	3.9%
Customer Acctg/Svc							
Assigned	4,713,759	4,083,132	3,691,946	3,913,939	4,118,663	35,531	0.3%
Allocated	8,059,444	8,437,246	9,043,185	10,568,819	13,495,280	5,058,034	16.9%
Total Customer Acctg/Svc	12,773,203	12,520,379	12,735,130	14,482,758	17,613,943	5,093,565	12.1%
A&G							
Assigned	5,184,063	6,803,082	7,610,207	5,946,228	6,137,391	(665,690)	-3.4%
Allocated	5,516,168	7,873,198	8,353,537	8,276,996	10,589,597	2,716,400	10.4%
Total A&G	10,700,231	14,676,279	15,963,744	14,223,224	16,726,989	2,050,709	4.5%
Totals							
Assigned	13,603,675	14,415,339	13,067,742	12,527,098	13,581,639	(833,699)	-2.0%
Allocated	28,399,365	39,136,739	42,045,954	40,412,338	51,411,285	12,274,546	9.5%
Grand Total	42,003,040	53,552,078	55,113,696	52,939,436	64,992,924	11,440,846	6.7%
Labor Adjustment				(754,000)	(922,000)		
Adjusted Total	42,003,040	53,552,078	55,113,696	52,185,436	64,070,924	10,518,846	6.2%

2020 Vision Capital Costs
($ Millions)

Phase	Project	2009	2010	2011	2012	2013	2014	2015	2016	Totals
Phase 1	Enterprise Asset Management Foundation	3.21	4.53	6.29						14.03
	Financial System Replacement	1.90	16.61	5.60	-	-	-	-	-	24.11
	Infrastructure and Program Office	0.10	3.10	1.13						4.33
Phase 1 Total		5.21	24.24	13.02	-	-	-	-	-	42.47
Phase 2	GIS		-	8.97	7.35	0.27	-	-	-	16.60
	Infrastructure (Phase 2)				5.18	2.71	0.90	1.05		9.84
	Mobility Foundation				0.02	0.08	0.05			0.14
	Mobility Hardware				1.33	0.64	0.56	0.57		3.09
	MWM		-		1.60	6.24	3.33	-	-	11.18
	OMS		-		-	5.58	5.71	-	-	11.29
	PeopleSoft Time and Labor				2.19					2.19
	Program Office				0.93	0.97	0.52			2.43
Phase 2 Total			-	8.97	18.60	16.50	11.06	1.62	-	56.75
Phase 3	DMS Upgrade					0.20	0.27			0.47
	EAM Distribution (WM)						4.42	6.14	5.87	16.43
	EAM IT						1.80	1.81		3.61
	EAM Supply Chain						0.11	0.15		0.26
	Program Office						0.52	1.06		1.59
Phase 3 Total						0.20	7.12	9.17	5.87	22.36
Grand Total		**5.21**	**24.24**	**21.99**	**18.60**	**16.69**	**18.19**	**10.79**	**5.87**	**121.58**

2020 Vision Roadmap



Process Only
Technology & Process
Stabilization

* Process Improvement Initiatives include: Increase Paperless Billing Adoption, Web Initiatives 2013+, Increase IVR Resolution Rate, Quality/Metrics/Performance Management, Knowledge Management & Governance, Actionable Customer Experience Design

** SEDC Projects include: Design Consistency, Job Drawing, Framing Hole Digger Phase 1, Right Crew Size and Configuration, Wave 2 Line Standardization Strategy, and Technical Skills Training

IT Vision Initiatives

Initiative		Description	Benefit Drivers
Move Non-IT roles to Other Departments	Partner with the Business	■ Identify non-IT roles such as Engineering and Purchasing and move if appropriate to other departments where the role is a core function.	Business Agreement
Business Relationship Management (BRM)	Partner with the Business	■ Complete detailed design of the structure, roles, and responsibilities of the function. Align plans with business priorities, Establish SLA and establish and provide the business with an SLA scorecard.	Improve Service
Demand and Supply Management	Partner with the Business	■ Complete Detailed Design of Demand Entry Process. Develop a Standard Estimating Method and Templates. Completed Detailed Design of the Supply Management Process that Aligns with Business Priorities: Evaluate and Implement a Portfolio Management Tool.	Process Efficiency
Simplify the Application Portfolio	Eliminate Complexity	■ Reduce number and the complexity of the application portfolio. Execute previously identified rationalization projects. Standardize the tools being used .	Reduced software licensing and maintenance
Workforce Management	Build Strong Workforce	■ Transform Talent Management. Define Resource Models and Career Paths. Identify and Mitigate Leadership, Functional and Technical Skill Gaps.	Process Efficiency
Sourcing Strategy and Vendor Management	Source Strategically	■ Finalize Sourcing Approach/Strategy and Timeline. Execute Sourcing Strategy for each bundle / phase.. Refine Vendor and 3rd Party Qualification Framework and Criteria. Transform Supplier Management Process and governance.	Increase Capability
Centers of Excellence	Standardize Processes	■ Define Centers of Excellence (CoE) and Implementation Plan. Implement CoE's for Business Analysis, Testing & Integration capability areas.	Process Efficiency
Office of the CIO	Meet Service Expectations	■ Complete Detailed Organizational Design, Develop Processes and Establish new roles. Develop IT Operational Performance Management Process and centralize IT Metrics.	Process Efficiency Business Transparency Reduced software licensing and maintenance

Green boxes represent 2013 priorities

IT Vision Initiatives

Initiative		Description – Details in Appendix	Benefits
Architecture and IT Strategy	Standardize Processes	Detailed Design of the IT Strategy and Architecture Operating Model. Establish Leading Common Processes and Tools. Define Standard Migration Roadmap. Buy vs. Build Analysis and Alternatives Analysis.	Process Efficiency Standardization
Simplify Infrastructure Portfolio	Eliminate Complexity	Reduce Infrastructure Volumes of server instances. Streamline the tools being used by infrastructure teams. Reduce Desktop complexity and risk. Develop a strategy to archive or remove data in a reasonable time frame.	Process Efficiency Standardization
Project Management and Governance	Eliminate Complexity	Enhance the Project Management Framework. Establish Metrics Reporting. Define a Budget Reporting and Accountability Process. Define a Stage Gate Review Process.	Process Efficiency
Information Risk Management	Standardize Processes	Define and implement a rigorous risk management process.	Process Efficiency
Solution Delivery	Standardize Processes	Establish and Improve Release Management Capabilities. Develop a Decision Framework for determining the Appropriate Delivery Methodology.	Process Efficiency
Service Management	Standardize Processes	Complete the metrics activities. Reduce Incident/Problem Frequency and Resolution Rates. Improve Service Transition Handoff from Development to Operations. Improve Operations Documentation. Define a Service Catalog.	Process Technology Efficiency
Initiative Program Oversight		Provide oversight and reporting on the IT Vision initiatives, track and validate costs and savings realized.	Ensure Execution

Green boxes represent 2013 priorities

Virtualized Server Avoided Cost Benefit

Approx. Physical Server Cost	$	8,000
Approx. Virtualized Server Cost	$	2,500
Avoided Purchase Savings	$	5,500

UNIX Infrastructure	2009	2012
Total Physical	62	75
Total Operating Server Count	121	345
% Virtualized	50%	78%
# servers /UNIX admin	30	86.5

Delta in Total OS	224
Less: Increase in Physical Servers	13
Delta in Virtualized Server	211
Avoided Cost	$ 1,160,500

Windows Infrastructure	2009	2012
Total Physical	286	232
Total Operating Server count	397	788
% Virtualized	28%	71%
# servers / Windows admin	50	99

Delta in Total OS	391
Less: Increase in Physical Servers	0
Delta in Virtualized Server	391
Avoided Cost	$ 2,150,500

Total Avoided Cost (both Unix & Windows)	$	3,311,000

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 262

Generation

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Stephen Quennoz
David Weitzel

February 15, 2013

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I. Introduction

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

A. My name is Stephen Quennoz. My position at PGE is Vice President, Power Supply. I am responsible for all aspects of PGE's power supply generation.

My name is David Weitzel. My position at PGE is Project Manager, Regulatory Affairs.

Our qualifications are included in Section VI of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to support the operations and maintenance (O&M) budget and present the planned capital expenditures associated with PGE's long-term power supply resources. We discuss the superb performance of PGE's plants in recent years, our ongoing efforts to improve plant performance and reliability, and our continuing efforts to reduce plant emissions. We also review the regional market conditions that influenced the manner in which we operated our plants in 2011, ultimately leading to below-average dispatch and, thus, below average costs incurred for those expenses that vary with generation.

Q. What are PGE's goals for plant operations and maintenance?

A. Our primary goals with respect to plant-related activities are to maintain high-levels of plant availability and system reliability in order to maximize our ability to provide safe, reliable, adequate power to our customers at a reasonable price. We achieve these goals by being thoughtful in our maintenance practices, performing the appropriate maintenance in a timely fashion, and making the necessary investments in our facilities. High availability allows PGE's power operations group to dispatch our plants whenever the plants' variable costs are less than the market price of power, thereby keeping net variable power costs (NVPC) low for customers. High system reliability ensures that we meet our obligation to serve on-demand customer loads.

Q. How is the remainder of your testimony organized?

A. Our testimony is organized into the following sections:

- Section II: PGE's Generation Resources
- Section III: Generating Plant O&M
- Section IV: Generating Plant Capital Expenditures
- Section V: Environmental Services
- Section VI: Qualifications

II. PGE's Generation Resources

A. Generation Resources

Q. Have you prepared an exhibit that shows all of PGE's power supply resources for the 2014 test year?

A. Yes. PGE Exhibit 701 lists PGE's generating resources and their expected energy output as modeled under normal hydro conditions for PGE's initial 2014 NVPC forecast presented in PGE Exhibit 400.

Q. Have PGE's long-term power supply resources changed significantly since the UE 215 rate case?

A. No. However, PGE expects significant changes to its resource portfolio over the next several years as the resources from our ongoing requests for proposals (RFP) for energy, capacity, and renewable resources, which we discuss below, are added to our portfolio.

Q. Please provide an update of PGE's current energy and capacity RFP.

A. On March 22, 2011, the Commission opened Docket No. UM 1534 for PGE's issuance of an energy RFP seeking 300–500 MW of baseload energy. Also on March 22, 2011, the Commission opened Docket No. UM 1535 for PGE's issuance of a capacity RFP targeting 200 MW of flexible, year-round capacity, bi-seasonal (winter and summer) capacity of 200 MW, and 150 MW of winter-only capacity. On September 27, 2011, the Commission issued Order No. 11-371, which directed PGE to combine the Capacity RFP with its baseload Energy RFP. The Commission approved PGE's final draft RFP for new energy and capacity resources in Order No. 12-215 issued on June 7, 2012. The final RFP was issued publicly on June 8, 2012. PGE's benchmark bids were submitted on August 1, 2012. All other bids were due on August 8, 2012. In response to the RFP, PGE received 32 bids representing 15 different generating projects. The bids include a mix of projects to be sold to PGE pursuant to asset purchase agreements and projects that would sell power to the utility under long-term purchase agreements. On January 31, 2013, PGE announced that the Port Westward Unit 2 flexible capacity benchmark resource was selected as the successful capacity bid. Negotiations for seasonal capacity products and baseload energy projects are ongoing. We currently expect the final base load energy resource selection resulting from this RFP to occur in the first half of 2013.

Q. Please discuss the status of PGE's current renewable resources RFP.

A. On June 27, 2012, the Commission opened Docket No. UM 1613 for consideration of PGE's RFP for Renewable Energy Resources. This renewable RFP requests approximately 100 MWa of Oregon renewable portfolio standard (RPS) compliant resources to be online between 2013 and 2017. The minimum size requirement is 10 MW, with duration of at least ten years. PGE issued the final RFP publicly on October 1, 2012. PGE's benchmark bid was submitted on October 30, 2012, and third-party bids were received on November 13, 2012. PGE expects final resource selection(s) to occur in the first half of 2013.

Q. Does PGE include the resources currently being pursued through these RFPs in this general rate case proceeding?

A. The outcomes of the RFPs will become known during the course of this proceeding. Depending on the outcomes, it is possible that PGE could have new resources in service in 2014. PGE has included forecasted expenditures to estimate the need for additional debt and equity financing. At the times the RFP outcomes are released, PGE will learn the extent and timing of any capital additions, and will adjust the financing assumptions in its revenue requirement in this proceeding accordingly. A full discussion of the considerations surrounding inclusion of amounts related to the RFP resources is presented in PGE Exhibits 300 and 1100.

B. PGE Plant Performance

Q. How have PGE's plants performed recently?

A. The performance and availability of PGE's generating resources are top priorities for the Generation organization. As a long-term goal, we target plant performance and availability in the top-quartile of an industry peer group. In 2011, the majority of PGE's plants exceeded the stated goals for performance in terms of cost per unit of output. Port Westward was recognized as achieving the best heat rate for a gas-fired resource in 2010 and was again recognized in the top-ten in 2011.[1,2] PGE completed an upgrade at the Coyote Springs plant in 2011, the results of which have exceeded initial performance expectations and will serve to enhance this plant's performance in future years, as we discuss below. On a year-to-year basis, realized plant availability is a key factor in evaluating the Generation organization. Nearly all of PGE's generating facilities exceeded the stated goals for their availability in 2011.

Q. How did Port Westward's dispatch in 2011 compare with prior years?

A. Port Westward dispatched considerably less in 2011 than in prior years. The graph below summarizes the recent Port Westward generation, demonstrating the extent to which Port Westward's generation level was substantially lower relative to prior years and to PGE's current 2014 forecast included in this filing.

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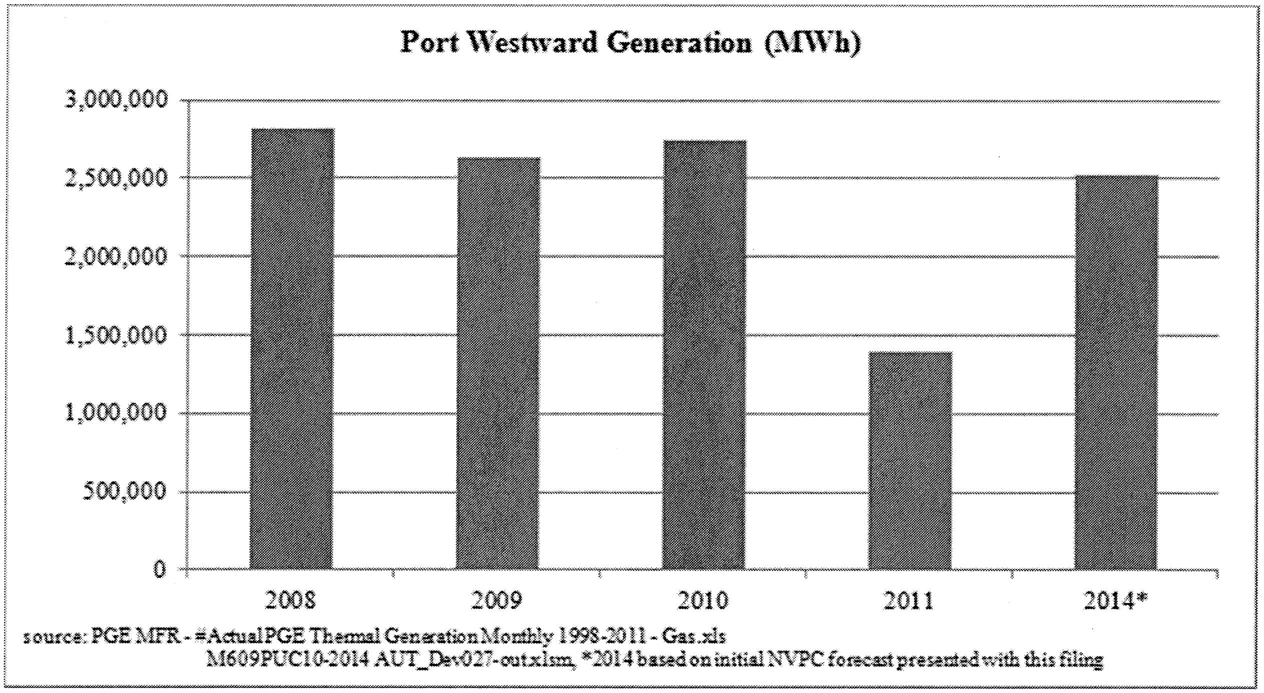
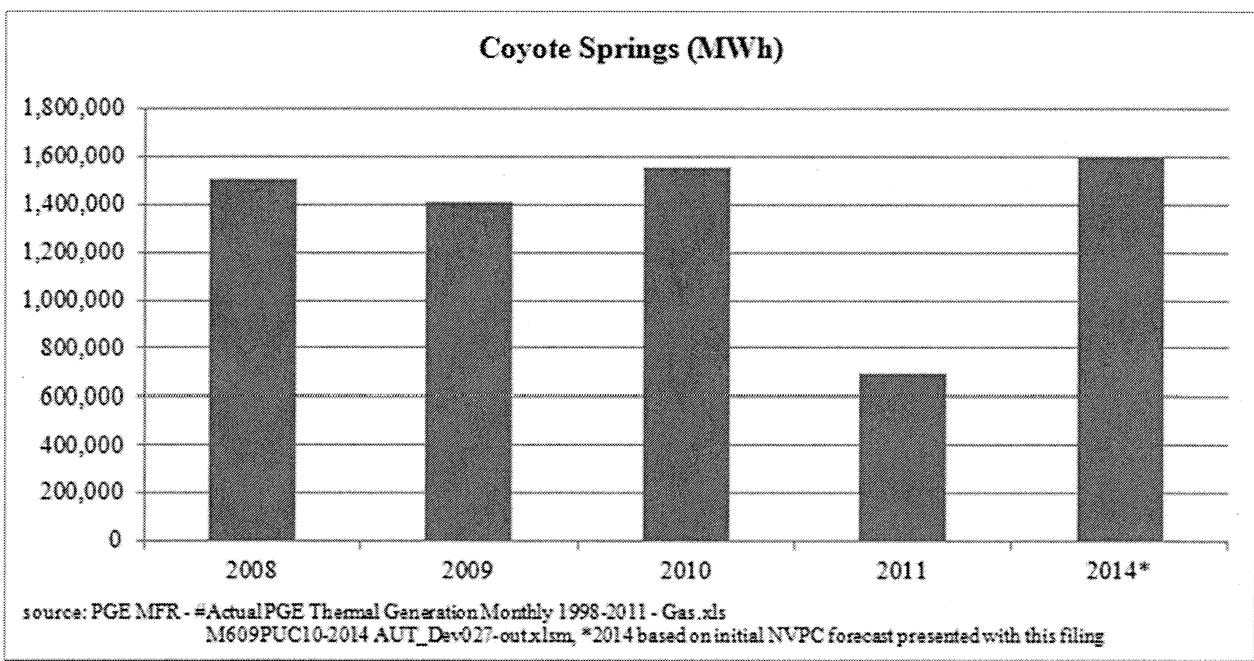
[1] As reported by "Electric Light & Power": http://www.elp.com/articles/print/volume-89/issue-6/features/operating-performance-rankings-2010-top-20-power-plants.html, and http://www.elp.com/articles/print/volume-90/issue-6/features/2011-operating-performance.html.

[2] Heat rate is a measure of a thermal generating plant's efficiency, relating the amount of heat input (Btu) required to generate one unit of energy output (kWh).



Q. Did Coyote Springs' dispatch mirror Port Westward's in 2011?

A. To a large extent, yes. Coyote Springs' level of dispatch was substantially lower relative to prior years as well.

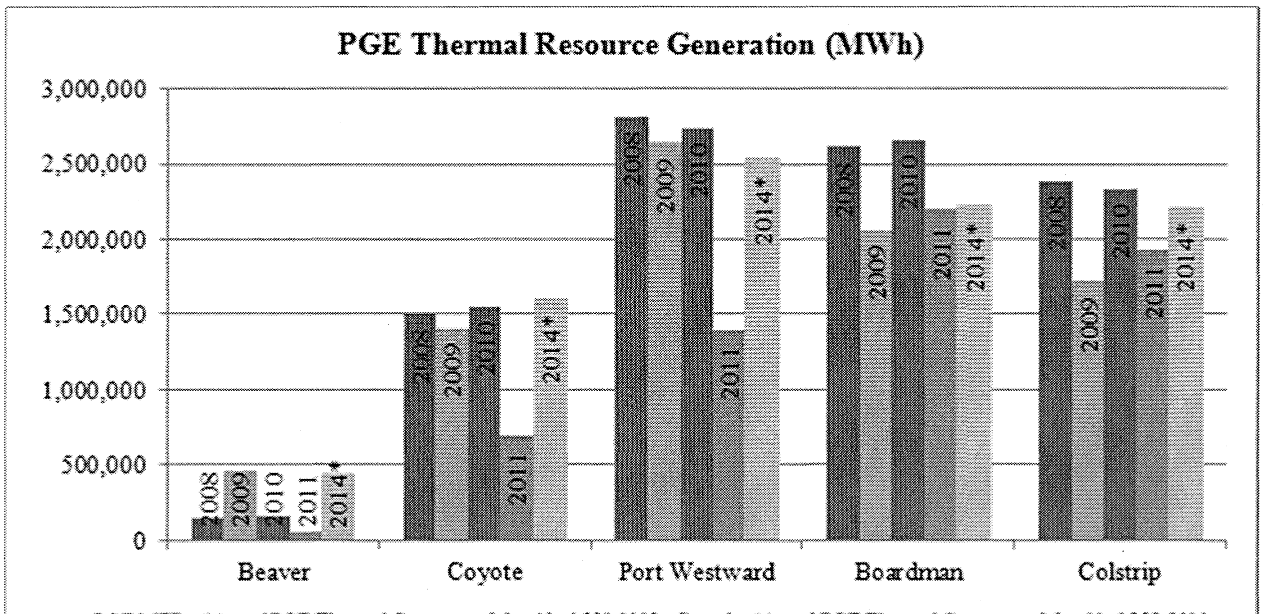


Q. Why did Port Westward and Coyote Springs dispatch less in 2011 than in prior years?

A. The key factors that contributed to the reduced level of generation, especially from PGE's gas-fired resources, in 2011 were the above-average streamflows (quantity) and the extended hydro season (timing) in the region. Both of these factors contributed to lower regional power market prices, which displaced thermal resources.

Q. Were all of PGE's thermal resources affected?

A. To some extent. While generation from PGE's coal-fired resources was not drastically out-of-line with the levels of production seen during the 2008–2010 period, these coal-fired plants were economically displaced more often than in preceding years. We summarize PGE's thermal plant generation information in the chart below, along with PGE's current 2014 forecast for each thermal resource included in this filing.



source: PGE MFR - #Actual PGE Thermal Generation Monthly 1998-2011 - Gas.xls, #Actual PGE Thermal Generation Monthly 1998-2011 - Coal.xls, M609PUC10-2014 AUT_Dev027-out.xlsm, *2014 based on initial NVPC forecast presented with this filing

Q. Did PGE's customers benefit from the lower market prices resulting from the above average hydro conditions that served to displace PGE's thermal resources in 2011?

A. Yes. In 2013, PGE's customers are receiving a direct benefit in the form of an approximately $5.5 million refund through Schedule 126 pursuant to the Power Cost Adjustment Mechanism (PCAM) as authorized by Commission Order No. 12-402 in Docket No. UE 256.

Q. Did this reduced level of generation also have an effect on the costs incurred by PGE in 2011?

A. Yes. The costs incurred for maintenance under the Long-Term Service Agreements (LTSA) in-place for PGE's Coyote Springs and Port Westward plants are largely determined by the number of hours the machinery is operating. If the plant is dispatched less, less costs are incurred. Likewise, if the plant is dispatched more than forecast, more costs are incurred. The balancing accounts proposed for Port Westward and in-place for Coyote Springs help to alleviate the variability arising out of this relationship. We discuss these balancing accounts in PGE Exhibit 300 and in Section III/C below.

Q. Did PGE actually incur fewer costs than budgeted for the Coyote Springs and Port Westward LTSAs in 2011?

A. Yes. The reduced dispatch of Coyote Springs and Port Westward in 2011 led to approximately $3.9 million savings relative to the budgeted LTSA payments.

Q. Do PGE's customers also benefit when PGE's plants operate more reliably?

A. Yes. Low forced outage rates are a result of reliable plant operation. The annual NVPC forecast that serves as the basis for PGE's Schedule 125 uses a four-year rolling average of the actual forced outage rates experienced at PGE's thermal plants. When our plants are operating reliably, their low forced outage rates are automatically incorporated into this average. Relatively low forced outage rates benefit customers because the plants are able to provide more generation on a forecast basis. The reliable plant operation that gives rise to low forced outage rates can also benefit customers by reducing actual power costs as our plants are available for dispatch when it is cost-effective.

III. Generating Plant O&M

A. Operations and Maintenance Practices

Q. How is PGE managing its O&M practices to improve plant and employee performance?

A. As we mentioned above, plant availability and performance are keys to our organization and our ability to serve customers. Additionally, we are seeking ways to establish safer and more efficient practices. To do so, we are continuing with our Generation Excellence initiative, including pursuing the underlying Reliability and Maintenance Excellence (R&ME) effort.

Q. What is Generation Excellence?

A. The Generation Excellence initiative was created to develop improvement efforts focused on the goals of employee safety, employee performance, process improvements, and reliability. This initiative has been presented in prior rate cases as well. Each goal supports plant reliability and availability, which are imperative to reducing forced outages and providing dependable service to customers. Generation Excellence acts as an umbrella for the centralization of sub-initiatives. R&ME was created to better align the various reliability and maintenance efforts with the established, and now centralized, initiatives including Reliability Centered Maintenance (RCM), and Maximo implementation. Maximo modernizes and consolidates PGE's mobile and scheduling tools into a single application and standardizes hardware; this system is now used for work and asset management, scheduling, and planning. Maximo is further discussed in PGE Exhibit 800.

PGE's approach to Generation Excellence, at a high-level, has been to make culture changes with regard to employee safety and performance, develop maintenance programs that better address the criticality of the underlying equipment, and support the integration of Maximo as part of an effort to improve and systematize PGE's maintenance work and workforce management.

Q. Please address the employee safety improvements that PGE has made.

A. All of PGE's thermal and hydro plants have achieved the Oregon Occupational Safety and Health Division (Oregon OSHA) Safety and Health Achievement Recognition Program (SHARP) status; these are employee-led efforts. Several plants are now pursuing U.S. OSHA Voluntary Protection Program (VPP) status, with one plant having already received certification. These programs promote a positive employee safety culture that improves employee safety processes, identifies and implements best practices, creates a better working environment that minimizes employee safety and health hazards, and increases communication between workers and management. Overall, our generation plants are adding emphasis to the importance of an employee safety culture within the plants, which enhances dependable performance.

Q. What improvements has PGE made to address employee performance?

A. New processes and procedures for management excellence, technical training, and operations qualification and testing have been implemented to help improve employee performance. Management excellence has been emphasized through scorecard tracking, budget reviews, one-on-one meetings with employees (exempt, non-exempt, and bargaining unit), ensuring training requirements are achieved, and continuing to recognize employee performance that exceeds expectations. Process objectives and timelines for these have been refined in an effort to establish accountabilities within Generation management.

Q. Why is PGE implementing new training practices and procedures?

A. As discussed in PGE Exhibit 500, PGE is facing several workforce-related challenges, including the expected retirement of a number of knowledgeable and highly-skilled employees. In response to this challenge, PGE is providing technical training at each plant to ensure that our employees are able to continue performing at their highest potential. The operations qualification and training procedures have been upgraded and standardized and now require checkouts, written exams, walk-through with senior shift supervisors, and oral exams with plant managers. Study guides have been developed to specifically address the requirements of the operation position.

Q. Can you provide an example of the increased training opportunities?

A. One example of the increased training opportunities is the Boardman plant simulator, which provides employees hands-on training for addressing accidents and other infrequently encountered conditions. These training opportunities help improve employee performance with respect to equipment operation and error reduction, which leads to improved plant reliability and availability.

Q. Please explain the R&ME initiative and expected improvements.

A. Generation Excellence continues to evolve, with the creation of new efforts to improve reliability and maintenance practices at PGE's plants. R&ME was established to act as PGE's overarching, comprehensive approach to reliability and maintenance. The goal is to maximize value and deliver on strategic objectives through better management of our assets over their entire life-cycle.

The primary drivers behind R&ME are the need to improve equipment and plant reliability, respond to increased regulatory requirements, incorporate risk management and life-cycle concepts, develop consistent data, and standardize the decision-making process. R&ME is expected to improve employee safety, increase plant reliability and availability, optimize maintenance cost and equipment life-cycle, and improve workforce efficiency and effectiveness.

Q. What is the status of R&ME implementation at PGE?

A. R&ME is a continuous strategy for PGE's generation organization. Presently, all plant managers are committed to the success of this initiative. The plants are expected to have site specific plans in place by the end of 2013 with the implementation of this effort beginning soon after. These plans are an assessment of the current repair strategies compared to an optimized maintenance strategy; this comparison derives a potential cost benefit for implementing the optimized strategy. The implementation of the R&ME strategy in PGE's generation organization should be complete by 2017, and is expected to improve reliability, reduce risk, improve maintenance efficiency and effectiveness, and utilize the flexibility of Maximo.

Q. Please explain RCM and the potential benefits associated with this initiative.

A. RCM is a key component of the R&ME initiative. RCM is a multi-year, plant-specific, corrective action maintenance plan. PGE's generation organization is using RCM to determine cost-effective maintenance strategies that address the main causes of equipment failure and improve equipment reliability. This is primarily accomplished by providing feedback regarding the maintenance and condition data of the equipment to the managers, technicians, and manufacturers. This information is instrumental in continually upgrading the specifications for equipment to allow for increased reliability.

The increased reliability resulting from RCM will lead to fewer equipment failures, and, therefore, lower maintenance costs and greater availability of the plants to benefit our customers. The cost of repairs decreases as failures are prevented and preventative maintenance tasks are replaced by condition monitoring. This obtains the maximum use from equipment by forecasting maintenance. Equipment is being replaced based on its condition rather than a particular calendar date. The net effect of this is a reduction of both repair and total maintenance costs. Optimizing the manpower to properly maintain the equipment and spare parts inventory is expected to reduce labor overtime, employee safety incidents, and the need to expedite orders for unexpected corrective work. The largest benefit to PGE will be the improvement of generation reliability and availability.

Q. How many analyses have been performed to date and what are the predicted benefits?

A. As of year-end 2012, eight reports have been completed by an outside consultant and a total of 23 RCM analyses have been performed (both internally and externally); benefits such as improved employee safety, increased plant availability, and optimized life-cycle maintenance costs have been identified. The majority of the benefit predicted by the RCM models is the result of increased reliability and availability, which reduces the potential replacement power costs arising from unexpected plant outages. PGE Exhibit 702 summarizes the completed reports, the hypothetical avoided replacement power cost benefit per year, and the potential annual O&M savings for each plant derived by comparing the current maintenance plan against the optimized plan. RCM plans are being developed to assess the maintenance of equipment not previously reviewed. Maintenance plans will continue to be reviewed and updated periodically to verify results and establish new practices as needed.

B. Plant O&M

Q. What are the changes in plant O&M between 2011 and 2014?

A. The changes in plant O&M from 2011 to 2014 are summarized in Table 1 below. These amounts include adjustments for emissions control chemical costs and various maintenance agreements, which we discuss in more detail below.

Table 1
Production O&M Summary
($000s)

Operating Area	**2011 Actuals**	**2014 Test Year**
Coal-fired Plants	39,272	41,832
Gas-fired Plants	27,396	27,258
Hydro Plants	11,594	19,955
Biglow Canyon	11,263	16,656
General & Miscellaneous	17,217	16,209
Total	**$ 106,742**	**$ 121,909**

* *Amounts exclude SunWay and Trojan entities*

Q. What are the main drivers for the changes in plant O&M presented in Table 1?

A. The main drivers of the increase in plant-related O&M between 2011 and 2014 are:

- Required maintenance at PGE's thermal plants, including inspections at Boardman and Port Westward;
- Recognition of the costs associated with the maintenance and repair contract at Biglow Canyon;
- Hydro plant activities, including required FERC license and Environmental Services projects;
- The addition of solar facilities; and
- FTE additions required to maintain reliable operations and meet growing needs.

We discuss each of these items in more detail below.

Q. How would the 2011 actual amounts in Table 1 change if PGE had not experienced the LTSA savings associated with lower dispatch at Coyote Springs and Port Westward discussed above?

A. Gas-fired O&M would equal approximately $31.3 million and total O&M would equal approximately $110.7 million if the budgeted LTSA expenses had been incurred in 2011.

C. Thermal Operations and Maintenance

Q. Please discuss the major O&M initiatives taking place at Boardman in 2014.

A. The major O&M activity taking place at Boardman in 2014 is the high pressure/intermediate pressure steam turbine inspection.

Q. What is the high pressure/intermediate pressure steam turbine inspection?

A. The Boardman plant has a high pressure/intermediate pressure steam turbine, and two low pressure steam turbines. A diagram of these parts is provided as PGE Exhibit 703. As detailed in that Exhibit, the high pressure and intermediate pressure turbines share the same rotating shaft (referred to as the "HP/IP"), and both turbines are serviced when maintenance is performed on the HP/IP. Due to normal stress and wear on turbine parts, and to comply with insurance requirements, it is necessary to periodically inspect and, as necessary, refurbish parts in the turbines. Approximately $1.0 million in maintenance related to the HP/IP inspection is expected in 2014.

Q. How is the HP/IP inspection interval determined?

A. Inspection intervals are provided by the manufacturer and may be adjusted based on the service history of the machine. For Boardman, the inspection interval for the HP/IP and low pressure turbines is 10 years. The HP/IP inspection is scheduled to occur in 2014, while the inspection of the low pressure turbines is currently expected to occur in 2016.

Q. Please explain the major Port Westward maintenance work taking place in 2014.

A. Port Westward has scheduled turbine inspections in 2014 and 2015 based on expected operating hours. Major inspections of the steam turbine and steam turbine generator are currently scheduled for the second quarter of 2014. These inspections include the HP/IP turbine, the low pressure turbine, and the generator and represent approximately $3.1 million of Port Westward's O&M budget in 2014. However, because of the infrequency of the inspections, we propose that this amount be incorporated into a balancing account as described below and collected over a period of five years.

Q. Have similar major inspections been performed at Port Westward since its commercial operation began in June 2007?

A. No. This will be the first major set of inspections of this equipment at Port Westward.

Q. Why must these inspections take place in 2014?

A. The manufacturer, Mitsubishi, states in its Operations and Maintenance Manual that the first major inspection for the steam turbine and its generator (as well as the gas turbine and its generator) must be conducted either six years after installation or prior to reaching 48,000 hours of operation. In 2014, the plant will be seven years old and is expected to have approximately 45,000 hours of operation. Delaying the inspections to 2015 (8 years and approximately 51,000 hours) is not practical since the gas turbine and its generator are currently expected to have their major inspections that year. Space, manpower, tooling, and crane constraints prevent simultaneous major inspections of both the steam and gas turbines. Delaying the steam turbine and generator inspections to 2016 (nine years and approximately 57,000 hours) is considered high-risk based on our current expectations. Thus, the inspections are scheduled for 2014 based on current projections of operational hours.

Q. Does PGE expect long-term service agreement costs at Port Westward to increase in 2014?

A. Yes. The LTSA at Port Westward covers regular inspection and maintenance of the plant's combustion turbine. PGE's LTSA payments are largely driven by the plant's operating hours (technically "equivalent operating hours", which also accounts for plant starts and various operating conditions in addition to service hours). We illustrated the extent of Port Westward's relatively reduced dispatch in Section II/B above. The level of dispatch realized by the plant is directly correlated to the LTSA costs. PGE's 2014 budget reflects a more "normal" level of operation and the associated LTSA costs relative to the actual lower-level experienced in 2011.

Q. Is PGE proposing a balancing account for the LTSA expenses at Port Westward?

A. Yes. As discussed in PGE Exhibit 300, PGE proposes a balancing account based on a projection of LTSA expenses and expenses related to the steam turbine and steam turbine generator as discussed above. We propose a levelized amortization amount of approximately $4.9 million that collects those projected expenses over a period of five years.

Q. Is the proposed balancing account for LTSA expenses at Port Westward similar to the major maintenance accrual PGE currently uses for Coyote Springs LTSA expenses?

A. Yes. PGE has used a similar mechanism for the expenses at Coyote Springs (the major maintenance accrual) since the UE 93 proceeding. For 2014, PGE proposes to update the amortization amount related to Coyote Springs to approximately $4.4 million from the $2.0 million amount last updated in PGE's UE 180 proceeding. Prior to the update in

UE 180, this amount was set at approximately $4.1 million. This proposal is also discussed in PGE Exhibit 300.

Q. Does PGE have maintenance work planned for Beaver in 2014?

A. Yes. The Beaver plant has six combustion turbines (Units 1–6) and one steam turbine (Unit 7). Beaver Unit 8 is a stand-alone 25 MW simple-cycle combustion turbine. An inspection is scheduled to occur in 2014 on the Unit 6 combustion turbine during the plant's annual major outage.

Q. Have changes to Beaver's maintenance practices been implemented as the result of the improvement initiatives you mentioned above?

A. Yes. Procedure changes are being implemented for critical plant evaluations by standardizing check sheets, formalizing the Preventative Maintenance Change Request forms, and establishing a process for core logic changes. In addition, Beaver is developing six additional critical check sheets which include reviews of shut-downs, start-ups, and lineup changes. These checklists are to be completed and implemented on an ongoing basis beginning spring 2013.

Q. Is a maintenance outage planned to occur at either Colstrip Unit 3 or Unit 4 in 2014?

A. Yes. PGE owns a 20% share of the Colstrip Unit 3 and Unit 4 generating facilities. These plants are on three-year maintenance outage cycle schedules as specified in the Colstrip business plan. Unit 4 is scheduled for a maintenance outage in 2013 and Unit 3 is scheduled for a maintenance outage in 2014.

Q. Are these planned maintenance outages accounted for in PGE's 2014 NVPC forecast developed in Monet?

A. Yes. Whether in a general rate case (GRC) or annual update tariff (AUT) proceeding, PGE's NVPC forecast reflects the power cost effect of planned maintenance outages expected to occur at PGE's plants during the test period (subject to certain procedural constraints regarding the timing of implementing updates). Planned maintenance outages are typically scheduled to occur during periods when the specific plant is expected to be economically displaced in order to minimize any power cost effects. The effects of these outages on O&M, however, are outside the scope of NVPC, and are generally only recoverable in a GRC proceeding.

Q. Please explain the agreements that cover maintenance and repair work at the Biglow Canyon wind farm in 2014.

A. Biglow Canyon has a Service and Maintenance Agreement (SMA) and Guaranteed Availability and Warranty Extension (GAWE) agreements that represent the majority of the O&M costs expected for Biglow Canyon in 2014.

Q. What is the SMA?

A. The SMA at Biglow is similar to an LTSA contract at a thermal plant. It covers regular, scheduled maintenance on the wind turbines.

Q. Please explain the Biglow Canyon warranty extension agreement.

A. The turbine supply agreements (TSA) with Siemens include extended warranties under which Siemens covers any repairs needed on the turbines at Biglow Canyon Phase II and Phase III. These extended warranties cover the three-year period ending in August 2014 for Phase II and August 2015 for Phase III. The first two years of operation were covered under

Siemens' standard warranty. The payments for these repair agreements were made prior to plant commissioning, consistent with the schedules defined in the TSAs, and the associated costs are being amortized over the three-year life of each agreement. The cost associated with the initial two-year period was not explicitly recognized in the respective years' O&M budgets, which creates the appearance of an O&M increase in years where the costs of repair agreements are explicitly recognized.

Q. What types of work are covered under Siemens' extended warranty?

A. The Siemens warranty covers the cost of materials and labor for any repair work needed to the entire turbine, including the gearbox, blades, generator, and main shaft bearing, over the three-year period.

Q. How much of the $5.4 million increase in Biglow Canyon O&M between 2011 and 2014 summarized in Table 1 does the recognition of the GAWE agreement represent?

A. Recognizing the cost of the warranty agreement represents approximately $4.8 million of the O&M increase at the Biglow Canyon operating unit. While the agreement was paid for up-front, as required under the TSA, the amortization of that amount represents the annual cost of obtaining a comprehensive repair and maintenance contract.

Q. You noted that the term of the Siemens extended warranty ends in August 2014 for Biglow Canyon Phase II. What is assumed for maintenance and repair costs for the balance of the year?

A. PGE is evaluating several options to obtain maintenance and repair coverage when the Siemens warranty period lapses; extending the agreement with Siemens is one of these options. PGE's budget for maintenance and repair work at Biglow Canyon Phase II for the remainder of 2014 is based on a quote obtained from Siemens to extend the coverage period.

Q. The costs associated with emissions control chemicals are discussed in PGE Exhibit 400 (NVPC) and included in the calculation of PGE's 2014 NVPC forecast. Have costs of these chemicals been removed from the O&M budgets presented in this testimony?

A. Yes. The costs of the emissions control chemicals discussed in PGE Exhibit 400 have been removed from the O&M budgets presented in our testimony. Information supporting this adjustment is included in the work papers accompanying PGE Exhibit 300. The updates to PGE's 2014 NVPC forecast will include the most recent estimates for chemical cost and usage amounts.

Q. Is PGE pursuing other means to reduce plant emissions at Boardman?

A. Yes. We discuss the capital expenditures related to the dry sorbent injection (DSI) system at Boardman in Section IV below. Relative to the other emissions control systems in place at the plant, the DSI system is complex in nature. Unlike the mercury emissions controls that were previously installed, the DSI system is a very large plant consisting of a switchgear, several large compressors, several grinding mills, four large silos, and a rail car handling engine. Despite this added complexity, PGE plans to manage the operations with existing plant personnel.

Q. PGE Exhibit 400 (NVPC) also describes costs associated with the biomass project at Boardman. Are costs related to this project included in PGE's O&M budget for 2014 presented in this case?

A. No. The O&M costs associated with the biomass project and test burn at Boardman are fully-contained within the values presented in the context of PGE's 2014 NVPC forecast in PGE Exhibit 400.

Q. Why are the costs associated with the biomass project and test burn at Boardman presented as part of PGE's NVPC forecast, rather than in the O&M budget?

A. The costs of growing and procuring biomass, and then torrefying (the "roasting" process that turns green biomass into a charred material that will be used as fuel) that material in order to burn it will be accounted for by PGE as fuel inventory. This fuel inventory will be expensed as a fuel cost when the test burn takes place. For these reasons, as well as the need to estimate the effect of energy produced during the test burn, PGE will include the costs in the NVPC forecast, rather than O&M. A detailed discussion of the biomass project at Boardman is presented in PGE Exhibit 400.

D. Hydro Operations and Maintenance

Q. Why is PGE budgeting for increasing O&M expenditures at its hydroelectric facilities?

A. The O&M budgets at PGE's Westside Hydro plants are increasing largely because of activities required by PGE's hydro license, Environmental Services activities, and the allocation of IT resources.

The increasing O&M budgets at PGE's Pelton and Round Butte hydro plants are largely attributable to the Environmental Services projects underway. Environmental Services activities are discussed in more detail in Section V below and also in PGE Exhibit 705.

Q. What are PGE's Westside Hydro plants?

A. PGE's Westside Hydro plants include the Sullivan facility on the Willamette River, and the Faraday, North Fork, Oak Grove, and River Mill plants on the Clackamas River (Clackamas Project), which are governed by the new Clackamas River Hydroelectric Project License (Clackamas License). The new license was issued in December 2010 with a term of 45 years. The license establishes operational and other requirements for these facilities.

Q. Please explain the required license activities that are responsible for the O&M increases at PGE's Westside Hydro facilities?

A. One project driving the hydro licensing O&M increase at PGE's Westside Hydro facilities from 2011–2014 is the implementation of the Recreation Resources Management Plan (RRMP), as mandated by the Clackamas License allowing continued operation of the Clackamas Project. The RRMP includes expenses for the operations of recreation sites, implementation of the law enforcement program, road maintenance, an interpretation and education program, and miscellaneous United States Forest Service (USFS) fees. The O&M associated with this Clackamas License requirement is approximately $0.5 million of the increase in PGE's O&M budget from 2011 to 2014.

Q. Are the O&M expenses for the RRMP offset by revenues collected from these recreation sites?

A. Yes, to some extent. Forecasted revenues offset approximately one-third of the O&M budget for this project. These revenues are included in the calculation of PGE's revenue requirement in this case presented in PGE Exhibit 300.

Q. Are there other increases at Westside Hydro plants related to the new Clackamas License requirements?

A. Yes. Under the new Clackamas License requirements, PGE will now be responsible for the maintenance of a campground previously administered by the USFS. This increases PGE labor at Timothy Lake for seasonal and recurring labor, oversight of general maintenance, reservations systems, and supervision of PGE seasonal labor. We discuss the FTE additions related to this requirement below.

Q. Are Environmental Services projects taking place at PGE's Westside Hydro facilities?

A. Yes. The main driver of cost increases for the Environmental Services expenditures at the Clackamas Project is the required activity at the North Fork plant. We discuss Environmental Services projects in greater detail in Section V below, and in PGE Exhibit 705.

Q. Please explain the $1.6 million increase in the IT allocation to PGE's Westside Hydro plants between 2011 and 2014.

A. The increase in the IT allocation to PGE's Westside Hydro plants is a function of an increase in the base IT budget and a change in the allocation methodology, which results in these departments receiving a relatively larger percentage of the base amount in 2013 and 2014 than in prior years. A portion of this increase at the Westside Hydro plants is offset by a decrease in the IT allocation at Beaver. PGE's IT activities and allocations are discussed in PGE Exhibit 600.

Q. Please describe the Pelton and Round Butte hydroelectric plants.

A. PGE's Pelton and Round Butte complexes are located on the Deschutes River. The Confederated Tribes of the Warm Springs Reservation of Oregon (Tribes) have a one-third ownership stake in these facilities.

Q. What activities are driving the increase at PGE's Pelton and Round Butte hydroelectric facilities?

A. At Round Butte, a $1.0 million increase in O&M expenses is allocated to Environmental Services and includes fish pathways and expenses connected with a 2-year study of downstream macroinvertebrates in compliance with the Section 401 Water Quality certificate as part of Article 416 of the Pelton-Round Butte FERC License. We describe this and other projects in more detail in Section V below.

E. Solar Facilities

Q. Why does PGE's O&M budget reflect approximately $350,000 for solar facilities in 2014?

A. This amount represents PGE's lease payments and O&M commitments for the Baldock solar facility. The Baldock facility came online in early 2012 and PGE began recovering the associated revenue requirement through PGE's Renewable Resources Automatic Adjustment Clause filing in Docket No. UE 249. We include these costs in base rates in this proceeding.

F. FTEs

Q. What is the increase in production FTEs from 2011 to 2014?

A. The total increase from 2011 to 2014 is approximately 31 FTEs in PGE's production departments. The table below summarizes where these increases occur.

Table 2
Production FTE Summary

Operating Area	2011 Actuals	2012 Forecast	2013 Budget	2014 Test Year
Coal-fired Plants	71	74	77	77
Gas-fired Plants	91	95	94	97
Hydro-related	96	100	102	103
Biglow Canyon	7	7	8	8
PSES	62	66	74	76
Environmental	29	31	33	34
Other (19 Departments)	96	99	101	101
PGE Adjustment	**0**	**0**	**(19)**	**(12)**
Total FTE	**452**	**473**	**471**	**483**

Q. How many of these positions that will be present in 2014 are filled in 2012 or 2013?

A. Approximately two-thirds of the FTE additions in Table 3 above are the result of hiring activities that occurred in 2012 to either meet new demands or maintain staffing at levels needed to ensure compliance and system reliability. In 2012, approximately 21 FTEs were added in PGE's generation departments. 12 new FTEs will be added in 2014.

Q. Does PGE make adjustments to the budgeted FTE amounts in order to account for expected unfilled positions in the budget and test years?

A. Yes. PGE adjusts the budget and test year FTEs to reflect expected vacancies (i.e., positions that will not be filled for the entire test year). For PGE's generation departments, this adjustment results in a reduction of 19 FTEs in 2013 and 12 FTEs in the test year. The process for budgeting and adjusting FTEs is discussed in detail in PGE Exhibit 500.

Q. Please explain the increases at Boardman.

A. Positions in both operations and maintenance at Boardman will be filled by 2014. Two Shift Supervisor positions were filled in 2012. Two Serviceman and one Instrument & Control (I&C) Technician positions were filled in 2011, and one I&C Technician position will be filled in 2013. In order for the plant to operate reliably long-term, it is critical that the operations and maintenance training pipeline remains filled by fully-staffing these positions.

Q. Please explain the increases at PGE's gas-fired plants.

A. Positions are added at PGE's Port Westward facility for warehouse operations, administrative support, and maintenance planning and scheduling to leverage the capabilities of Maximo. Contract labor is used to supplement PGE employees at Beaver during maintenance outages. The extent to which contractors are used is dependent upon the amount of maintenance work taking place. Additional contract labor, relative to 2011, is expected to be needed for the 2014 outage due to the scope of work planned.

Q. Please explain the increases related to PGE's hydro plants.

A. A project engineer position was added to the Westside Hydro department, and one I&C Technician will be added in 2013. As with many of PGE's other plants, contract labor supports maintenance activities at PGE's Westside Hydro facilities and varies depending upon the scope of work. Contract labor also fills seasonal needs for PGE. As we mentioned above, PGE is responsible for operations at the Timothy Lake campground under the new Clackamas License. Beginning in 2012, seasonal labor supports these campground operations.

Q. Please explain the FTE additions at Biglow Canyon.

A. A plant engineer was added in 2012. This position provides engineering support and analysis of the turbine performance. While a turbine may be running, engineering analysis can identify issues early or make corrections to operation parameters. This allows us to maximize output and ensure reliable long-term operation of the turbines. A wind technician was added in 2012 based on the increased level of work load experienced with the entire plant being online full-time.

Q. Please explain the Power Supply Engineering Services position additions.

A. Power Supply Engineering Services (PSES) provides administrative support, civil, electrical, and mechanical engineering services to PGE's generating plants and related departments. As a result of increasing regulatory requirements, a changing and aging generation portfolio, and new maintenance initiatives, PSES is expanding its workforce.

Q. What are the increasing regulatory requirements being addressed by PGE's engineers?

A. The key regulatory requirements facing PGE's PSES department are those imposed by the North American Electric Reliability Corporation's (NERC) Critical Infrastructure Protection (CIP) program. The requirements of CIP, including the recent additions with Version 5, are discussed in detail in PGE Exhibit 600. For PSES, implementing the requirements of CIP requires the addition of analytical and engineering support. All generation plants have digital control systems which require cyber security protection, including manual oversight of the data collection and monitoring processes. The implementation of new NERC reliability standards further increases the regulatory burden facing the PSES department. Two engineers have been added since 2011 to aid the development of the required protections. Two electrical engineers will be added, one in 2013 and one in 2014, to support regulatory compliance including CIP and cyber security requirements. A supervisor is added in 2014 to the electrical engineering group to oversee the Compliance staff, which reduces the span of control of the Electrical branch manager.

Q. What PSES positions are added or filled to support PGE's generating resources?

A. PSES performs capital and O&M project design and management, records management, and drawing control for PGE's generating plants. Aging facilities and plant upgrades require additional engineering and administrative support. Mechanical and electrical engineering, and designing and drawing control positions are filled in order to maintain staff with experience and exposure to PGE's plants. In 2012 and 2013, two electrical engineer positions are filled, including one engineer with expertise in programmable logic controllers vital to plant operation. A mechanical engineer is added in 2014 to augment the current mechanical engineering staff, which has remained at approximately the same staffing level since 2007 despite the addition of the Port Westward and Biglow Canyon facilities. A mechanical designer was added in 2012 to provide engineering design and compliance support. A supervisor will be added to the mechanical engineering group in 2013 to reduce the span of control of the Mechanical branch manager. Additionally, an administrative position to provide project cost estimation and budgeting support is filled in 2013. Adequate support from PGE's engineering department helps ensure long-term reliable operation of PGE's power plants, as well as the opportunity to benefit from upgrades and new technologies.

Q. What are the additions resulting from the reliability and maintenance initiatives being pursued by PGE's PSES department?

A. As we discussed above, PGE is continuing to implement its R&ME program as part of Generation Excellence. Rather than shift these responsibilities to the plants, R&ME is being centralized in the PSES department. In 2012, an R&ME engineer was added to support implementation and an analyst responsible for root cause analysis was added.

Q. Have other positions been filled or added to support PGE's generation organization?

A. Yes. We discuss the additions to PGE's Environmental Services department in more detail in Section V below. PGE Exhibit 704 provides additional detail for the FTE information summarized in Table 3 above.

IV. Generating Plant Capital Expenditures

Q. Please summarize plant-related capital expenditures from 2011 to the 2014 test year.

A. Table 3 below summarizes production capital expenditures, excluding amounts related to the RFPs discussed above, for 2011 and 2014. Additional information regarding PGE's planned capital expenditures is included in the work papers for PGE Exhibit 300.

Table 3
Production Capital Expenditure Summary
($1,000s)

Component	2011 Actuals	2014 Test Year
Operational Expenditures	27,200	29,472
Licensing Construction	15,900	27,920
DSG	3,500	4,000
Boardman Emissions	16,500	306
Other	20,300	0
Total Capital Expenditure*	**$ 83,400**	**$ 61,698**

**Does not include amounts related to the Energy and Capacity or Renewable resources RFPs.*

Q. Please explain the major plant-related capital expenditures that took place in 2011 and 2012.

A. The major capital expenditures in 2011 and 2012 were:

- Boardman emissions control projects in 2011, including installation of low-NO_x burners and the mercury control system, amounted to approximately $16.5 million.
- Projects related to hydro licensing construction in 2011 totaled approximately $15.9 million and $24.1 million in 2012.
- The Coyote Springs turbine upgrade accounted for approximately $20.3 million of PGE's capital expenditures in 2011. The results of the upgrade were better than projected; Coyote has achieved approximately a 12.3% improvement in output on a combined-cycle basis.

- Capital expenditures related to PGE's ownership share in Colstrip Unit 3 and Unit 4 total approximately $6.6 million in 2011 and $6.4 million in 2012.

Q. Please explain the major capital expenditures planned in 2013 and 2014.

A. The major operational capital expenditures planned in 2013 and 2014 are:

- Installation of DSI system for sulfur dioxide control in 2013 at Boardman accounts for $14.7 million. The chemical needs associated with the operation of the DSI system are discussed in PGE Exhibit 400.
- Capital expenditures related to the requirements of the Clackamas License total approximately $10.8 million in 2013 and $24.4 million in 2014.
- Purchase of two sets of coils and rewind of the #3 generator at Round Butte accounts for approximately $5.6 million in 2013. Approximately $3 million in 2014 is associated with the expected rewind of the #2 generator.
- Pelton-Round Butte License expenditures total approximately $10.1 million in 2013 and $3.4 million in 2014.
- Capital expenditures related to PGE's ownership share in Colstrip Unit 3 and Unit 4 total approximately $7.7 million in 2013.

Q. Why is PGE installing the DSI system at Boardman?

A. The Regional Haze Rules established by the Oregon Department of Environmental Quality ("DEQ") mandate a maximum level of sulfur dioxide emissions that must be achieved beginning July 1, 2014. The DSI system is being installed to help achieve compliance with the DEQ requirements. DSI is an emissions control system that reduces sulfur dioxide emissions by combining a dry alkaline reagent directly with the boiler exhaust gas stream. The reagent adsorbs sulfur dioxide and is then collected by the existing electrostatic precipitator. The sorbent material for the DSI system at Boardman is called "trona." The costs associated with trona are included in PGE's 2014 NVPC forecast, which is discussed in PGE Exhibit 400.

Q. Please explain the capital expenditures required by hydro licenses planned to occur in 2014.

A. The majority of the planned hydro license-related capital expenditures in 2014 are tied to the construction of the surface water collector at PGE's North Fork facility pursuant to the Clackamas License. This project accounts for approximately $19.2 million of the total licensing-related capital planned to be spent in 2014.

V. Environmental Services

Q. Why do you discuss Environmental Services in the Production testimony?

A. Environmental Services reports to PGE's Vice President, Power Supply, and provides general support to all of PGE's facilities, in particular production. Some examples of required compliance activities include monitoring wildlife, fisheries, air quality, and waste management/disposal.

Q. What is PGE's budget for Environmental Services in 2014?

A. PGE forecasts environmental costs to be $4.2 million, which represents an increase of $1.6 million since 2011. The costs consist of project-specific amounts and general Environmental Services support related to PGE's various generation facilities. Table 4 below provides a summary of environmental service costs for both categories.

Table 4
Environmental Services Budget
($Millions)

	2011 Actuals	**2014 Forecast**	**Delta**
Clackamas Project	0.5	1.6	1.1
Generation Support/Other	0.8	0.2	(0.6)
Pelton-Round Butte	$1.3	$2.4	$1.1
Total	**$2.6**	**$4.2**	**$1.6**

Q. Why is PGE's Environmental Services budget increasing?

A. There are two major components of the increase: the new FERC license requirements for PGE's hydro facilities at Pelton-Round Butte and at the Clackamas Project. The Environmental Services costs related to PGE's hydro facilities will increase by approximately $2.2 million. Offsetting this increase is a $0.6 million reduction in other generation support projects. We summarize the Pelton-Round Butte and Clackamas Project activities below and list project-specific details in PGE Exhibit 705.

Q. What are the primary features of the Pelton-Round Butte projects in 2014?

A. The FERC license requirements for the fish pathways and lamprey studies represent a significant increase. These license requirements involve biologists and technicians to operate the fish capture facility along with other fish facilities at the project year-round, involving long-term studies, program monitoring, and evaluating the reintroduction of anadromous fish above the plant. This also involves continued impacts on resident fish population, effectiveness of the Selective Water Withdrawal fish capture facility, and the potential for reintroducing lamprey above the plant. See PGE Exhibit 705 which provides the Pelton-Round Butte projects in detail.

Q. Please describe the primary features of the activities at the Clackamas Project.

A. The new FERC license for the Clackamas Project requires a significant increase for implementing aquatic projects and evaluating new fish facilities to ensure they meet established protection standards. See PGE Exhibit 705, which provides the Clackamas Project and Westside Hydro activities in detail.

Q. Have you had any FTE changes within Environmental Services from 2011 to 2014?

A. Yes. There are five new FTEs within Environmental Services: a biologist, a technician, two environmental science specialists, and an increase in temporary labor:

- The biologist position added in 2014 will be responsible for the Westside Hydro fisheries and implementing the Clackamas License. Currently, PGE employs five biologists, but the addition of new fish facilities and an increase in reporting requirements and assessment studies requires additional staff.

- The new technician added in 2012 will assume work from higher level specialists within the environmental group so that they can address the many environmental remediation projects and reporting requirements that have increased significantly during the last few of years.
- Two specialist positions support the increasing regulatory requirements and permit compliance (including air, greenhouse gas, and wildlife permits).
- Temporary labor supports PGE's ongoing Environmental Services projects at Pelton-Round Butte.

VI. Qualifications

Q. Mr. Quennoz, please describe your qualifications.

A. I hold a Bachelor of Science degree in Applied Science from the U.S. Naval Academy, and hold Masters Degrees in Operations Analysis from the University of Arkansas, Mechanical Engineering from the University of Connecticut, Nuclear Engineering from North Carolina State University, and an MBA from the University of Toledo. Prior to working for PGE, I held positions as Plant Superintendent at the Davis-Besse Nuclear Station for Toledo Edison and General Manager at the Arkansas Nuclear One Station for Arkansas Power and Light. I also coordinated restart of the Turkey Point Nuclear Station for Florida Power and Light. I joined PGE in 1991 and served as Trojan Plant General Manager and Site Executive. I assumed responsibilities for thermal operations in 1994 and hydro operations in 2000. I was appointed Vice President, Nuclear and Thermal Operations in 1998, and Vice President Generation in 2000. I've held my current position of Vice President, Power Supply since August 2004. My responsibilities include overseeing all aspects of PGE's power supply, as well as the decommissioning of the Trojan nuclear plant. I am a registered Professional Engineer (P.E.) in the State of Ohio.

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

A. I received a PhD in Economics from the University of Washington in 1980 with a field in econometrics. In 1997, I obtained the Chartered Financial Analyst (CFA) designation. I have worked in the Rates and Regulatory Affairs department since 2009.

My forecasting work includes two projects for the Electric Power Research Institute; for one project I estimated the effects of time-of-use pricing on residential electricity demand, and for a second project I estimated models to forecast industrial demand for energy. For

Puget Power, I created statistical models to forecast energy savings from residential conservation programs. As a member of the GTE (and later Verizon) Demand Analysis and Forecasting Group, I was responsible for research design and for forecasting demand for telecommunication services. Also at Verizon, I participated in the development of statistical testing protocols to assess parity of service provision in local telecommunications markets. With Insightful Corporation, I developed models to forecast demand for consumer goods. Miscellaneous projects include forecasting the price of oil tanker services, forecasting water demand, and models to predict credit problems.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
701	PGE Generating Resource Summary
702	Summary of RCM Analyses
703	Boardman Steam Turbine Diagram
704	Generation Organization FTE Summary
705	PGE Environmental Services Project Summaries for Westside Hydro and Pelton-Round Butte

	PGE's 2014 Generation Resources	Annual Energy (MWa)
	PGE Resources	
Coal	Boardman	254
Coal	Colstrip	253
Gas	Beaver	51
Gas	Beaver 8	0
Gas	Port Westward	289
Gas	Coyote Springs	182
Wind	Biglow Canyon	150
Hydro	Oak Grove	23
Hydro	North Fork	23
Hydro	Faraday	19
Hydro	River Mill	12
Hydro	Sullivan	14
Hydro	Round Butte	77
Hydro	Pelton	34
	PGE Resources Total	**1,381**
	Long-term Contracts	
Hydro	Wells	104
Hydro	Wanapum	44
Hydro	Priest Rapids	43
Hydro	Portland Hydro Project	10
Wind	Other Wind	37
Solar	SunWay Projects	0
Solar	Other Solar Contracts	2
Hydro	Other Hydro Contracts	62
Other	Various Other Contracts (Net)	112
	Long-term Contracts Total	**414**
	Total Resources	**1,795**

Estimated annual average generation assuming average hydro conditions
Energy reflects PGE's share of the resources

Summary of PGE Reliability Centered Maintenance (RCM) Studies

Plants	Potential Annual Benefit	Number of RCM Studies Completed/Reviewed					
		2008	2009	2010	2011	2012	2013
Boardman, Coyote Springs, Port Westward	$1,403,314	2			1	6	1

Note: additional analyses have been completed for Beaver, Boardman, Pelton Round Butte, and Westside Hydro plants.
Potential annual benefit above excludes effect of Boardman Intake Structure Study.

Total Potential Annual Avoided Cost	$1,403,314
Potential Annual Avoided O&M	($264,794)
Potential Annual Avoided Replacement Power Cost	$1,668,108

8. LIST OF AUXILIARY SYSTEMS

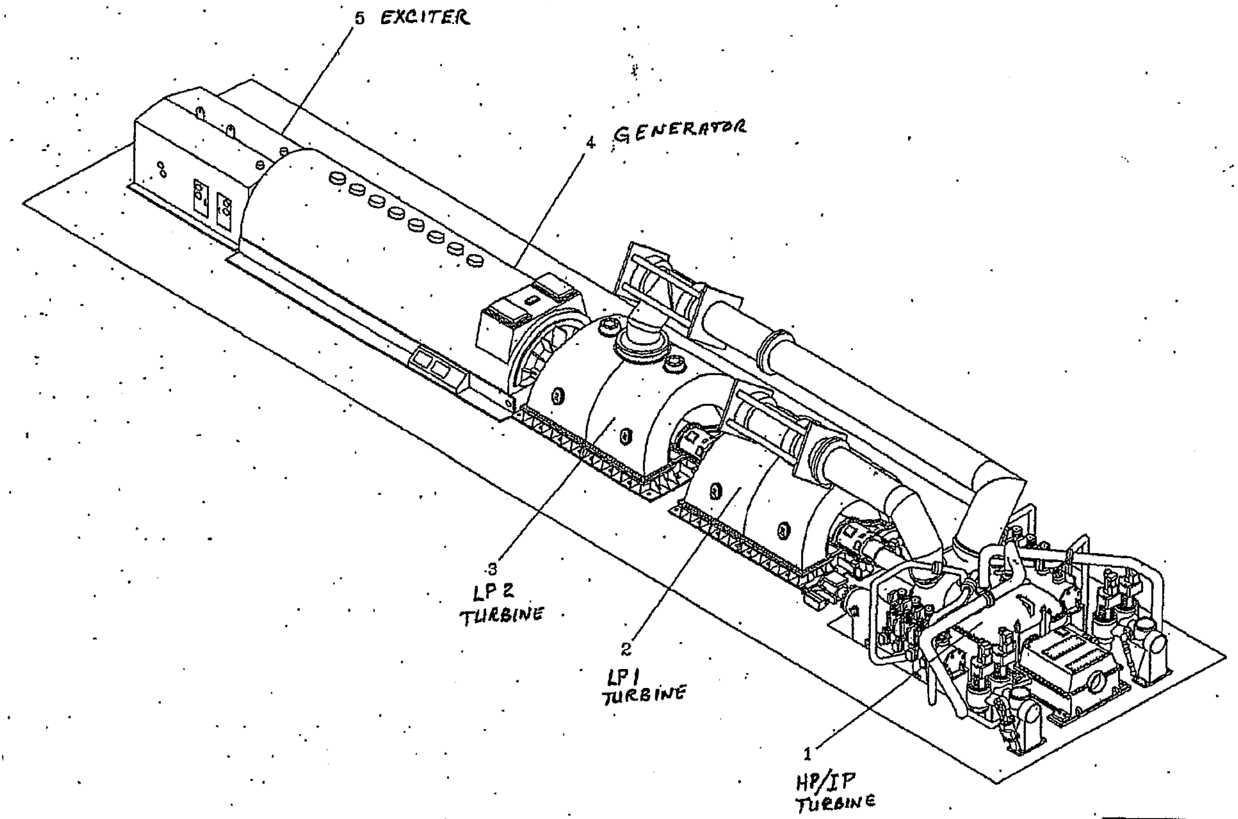


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Figure 1. BOARDMAN 1

Department	Incremental FTE	Position Description
011 - Transmission Contracts - Merchant	0.5	Renewable analyst added mid-year - 2011
Total	**0.5**	
012 - Fundamentals & Strategic Support		
015 - Preschedule Trading		
016 - Power Operations		
017		
019 - VP Power Operations & Resource Strategy	(1.0)	Project Manager retired, not filled - 2012
Total	**(1.0)**	
041 - Boardman Plant Administration		
042 - Boardman Plant Operations	1.3	2 Shift Supervisor positions filled to maintain adequate operations staff - 2012
	2.0	3 Operator Trainee positions filled to maintain trained operations personnel - 2012
Total	**3.3**	
043 - Boardman Plant Maintenance	1.0	2 I&C Tech positions filled to maintain adequate maintenance staff and training pipeline - 2011, 2013
	1.0	2 AA Serviceman positions filled to maintain adequate maintenance staff and training pipeline - 2011
Total	**2.0**	
044 - Boardman Plant Engineering		
061 - VP Power Supply / Generation		
062 - Trojan ISFSI Operations		
071 - Beaver Plant Administration		
072 - Beaver Operations		
073 - Beaver Maintenance	3.4	Contract maintenance labor varies with scope of work
Total	**3.4**	
081 - Coyote Springs Operations	1.0	Planner/Scheduler added - 2013
	(2.5)	Technician positions - 2012
Total	**(1.5)**	
086 - Port Westward Operations	1.0	Assistant - warehouse mangement / Maximo utilization added - 2012
	1.0	Field Buyer - administrative support, planning/scheduling added - 2013
Total	**2.0**	
091 - Biglow Canyon Wind Farm Operations	1.0	Plant Engineer - engineering support, performance optimization - 2012
	0.5	Technician - covers increased work load with full plant online - 2012
Total	**1.5**	
121 - West Side Hydro Projects	1.0	Manager/Engineer position added 2012 (previously rotating assignment)
	1.0	Operator poistion filled - 2013
	0.5	I&C Technician position added - 2013
	1.0	Contract maintenance labor varies with scope of work - 2012
Total	**3.5**	
161 - Pelton/Re-reg/Round Butte Operations	(0.6)	Senior I&C Tech position - 2013
Total	**(0.6)**	
171 - Power Contracts & Fuel Operations		
172 - Hydro Licensing	4.0	Contract Summer labor
Total	**4.0**	
174 - Structuring & Origination		
175 - Realtime Marketing Operations	1.0	RT Trader position filled - 2013
Total	**1.0**	
176 - Fuels Trading		
177 - Coal Supply Transportation		
551 - Power Supply Engineering Services	2.0	RCA analyst and RCM ME positions filled to support plant reliability initiatives - 2012
	2.0	EE positions filled to support plant operations inlcuding PLC - 2012, 2013
	1.0	ME Supervisor added to reduce span of control - 2013
	1.0	ME added to support workload from past resource additions - 2014
	4.0	EE added to support increased CIP, cyber security, and regulatory requirements - 2011-2014
	1.0	EE Supervisor added for Compliance oversight and reduced span of control - 2014
	1.0	Specialist to provide budgeting & project cost estimation control - 2013
	1.0	Lead Mechanical Designer added to provide engineering and compliance support - 2012
	1.0	CE position filled - 2013
Total	**14.0**	
554 - Generation Projects	1.0	Engineer added end of year - 2011
	1.0	Administrative Assistant added - 2012
Total	**2.0**	
556 - Integrated Resource Planning		
561 - Resource Strategy		
675 - Financial Risk Management Reporting & Control		
676 - Credit Management		
841 - Environmental Services	2.0	Enivronmental Specialists supporting increased permit compliance load - 2011
	1.0	Biologist responsible for the Westside Fisheries and implementing the Clackamas License - 2014
	1.0	Technician assuming work for higher level specialists to lead remediation projects and reporting requirements - 2012
	1.0	Contract and seasonal labor with Tribes at Pelton-Round Butte
Total	**5.0**	
924 - Customer Specialized Programs	1.0	Project Manager added - 2012
Total	**1.0**	
932 - Hydro Operations Support	1.0	Work Control Specialist added - 2013
Total	**1.0**	
Partial and Rounding	1.7	
Increase Before Unfilled Position Adjustment	42.8	
Unfilled Position Adjustment	(12.0)	*PGE Exhibit 500*
Net Increase Identified	30.8	

Exhibit 705 PGE Environmental Services Budget

Pelton Round Butte Projects	2014 Budget
FERC LICENSE RP416 - PME Fish and Water Quality Monitoring	120,577
The Pelton Round Butte Hydroelectric Project received a new FERC operating license in 2005. The license contained a number of license articles containing conditions/requirements for protection, mitigation and enhancements (PMEs) related to fish and wildlife resources associated with the Project. Of particular importance is the requirement to provide for the re-establisbment of native salmon and steelhead runs above the Project.	
FERC LICENSE RP420 - Round Butte Hatchery	502,666
The FERC license involves PGE and the Confederated Tribes of Warm Springs (Tribes) working with Oregon Department of Fish and Wildlife for the operation of Round Butte Fish Hatchery at no more than the current production levels of spring Chinook and summer steelhead during the term of the license. This requires PGE to conduct several test and verification studies to evaluate the effectiveness of new fish passage facilities and the fish passage program.	
FERC LICENSE RP421- Native Fish Monitoring	81,866
The Native Fish Monitoring program is the basis for evaluating the effects of reintroducing anadromous fish on resident fish populations in the Deschutes Basin above the Pelton Round Butte Project. The NFM Plan has two components: (1) biological and (2) habitat. The biological component includes a number of long-term tasks designed to assess spawning, distribution and timing for salmon and steelhead reintroduced above the Project, and to monitor and assess competition among salmon and steelhead with resident fish species in the Metolius and middle Deschutes River systems and McKay Creek (Crooked River system) upstream of the Project. The habitat component also includes several long-term provisions for assessing quantity of available habitat and habitat effectiveness and riparian conditions upstream above the Project, generating production capacity estimates for salmon and steelhead above the Project, and monitoring condition of habitat for any riparian habitat restoration projects undertaken by the Licensees.	
FERC LICENSE RP422 - PRB Terrestrial Resource Management	157,271
The Terrestrial Resource Management Plan (TRMP) is the principle instrument for management of, implementation, monitoring and adaption of Protection Mitigation and Enhancement measures for terrestrial resources affected by or related to the Hydro Project.	
FERC LICENSE RP433 - Lower Deschutes River Gravel Study	278,402
The gravel study is a 5-year study culminating in 2014. Under FERC license it is required to pull all five years of the study results into one report subject to a peer review panel before submitting it to FERC in February 2015. Budget for outside services was increased substantially to cover additional cost of gravel study consultant.expenses associated with completing a final year study, developing a 5-year report, and funding a 3-member expert panel review, per FERC license requirements."	
FERC LICENSE RP434 - PME Lower River Wood Management	16,511
The Lower River Wood Management program is a life-of-the-license requirement to collect large wood entering Lake Billy Chinook each year from the tributaries, transport the wood to the lower river below the Pelton Round Butte Project, and strategically place the wood along the shoreline of the Deschutes River to enhance habitat for fish and other wildlife. Some wood is to be secured in the upper reaches of the Metolius River Arm of the reservoir as well. The program also includes a provision for a monitoring plan to be conducted through the term of the license to evaluate effectiveness of placed wood, including river transport below the Project, use by wildlife and fish, and value in terms of erosion control and establishment of riparian vegetation.	
FERC LICENSE RP435 - Trout Creek Habitat Enhancement	146
FERC LICENSE RP436	
The Trout Creek Habitat Enhancement program involved implementation of a large-scale capital project to enhance stream habitat as described in Exhibit F to the Settlement Agreement for re-licensing the Pelton Round Butte Project. The program also included a provision for implementation of a 4-year follow-up monitoring plan to ensure effectiveness of the project. Monitoring concluded in 2012. As a consequence, no additional funding is requested and this license requirement has been met.	
Lamprey Fish Pathways - Sec 18	979,508
Manager Environmental RGENR	
The license required construction and operation of the massive selective water withdrawal (SWW) and fish capture facility at Round Butte Dam which was part of UE-&&&. Fish biologists/technicians are needed to operate the fish capture facility along with other fish facilities at the Project year-round. In addition, the license included a number of long-term studies and monitoring programs to evaluate the success of reintroducing anadromous fish above the Project, impacts on resident fish populations above the Project, effectiveness of the SWW-fish capture facility, and the potential for reintroducing lamprey above the Project. Current ongoing studies include native fish monitoring programs, assessing physical reservoir changes with operation of the SWW, monitoring the rearing survival and distribution of juvenile salmon/steelhead in the tributaries above the Project, juvenile/smolt migration through Lake Billy Chinook and capture efficiency of the SWW-fish capture facility, smolt downstream migration survival to Bonneville Dam, reservoir survival / predation/ fishery/disease associated with juvenile salmonids in Lake Billy Chinook, and returning adult salmon /steelhead migration /survival/ spawning in the tributaries above the Project. All of these studies are specific requirements of the FERC license.	
PRB PME - ODFW Fish Health Funding	209,563
Oak Grove - Flowline Lead Abatement	
The Pelton Round Butte Hydroelectric Project received a new FERC operating license in 2005. The license contained a number of license articles containing conditions/requirements for protection, mitigation and enhancements (PMEs) related to fish and wildlife resources associated with the Project. Of particular importance is the requirement to provide for the re-establishment of native salmon and steelhead runs above the Project. The program provides for the evaluation of disease as a mortality factor in downstream and upstream migrating anadromous salmonids and procedures needed to reduce the risk of transmitting pathogens upstream of the project.	
Miscellaneus	37,964
Fuel/Maintenance of vehicles -- Vehicles for PRB biologists; costs shared between Environmental Services and PRB Project. Office supplies, office cleaning, general admin support and other costs shared for the Pelton-Round Butte Project.	
Total 2014 Budget - Pelton Round Butte Projects	**$2,384,473**

PGE Environmental Services Budget

Westside Hydro Projects	2014 Budget
The new FERC license for the Clackamas Project requires a significant increase for implementing aquatic projects and evaluating new fish facilities to ensure they meet protection standards.	
NORTH FORK-IMPROVE DS FISH MIGRANT	281,071
Under the Clackamas project FERC license, PGE was required to construct or modify adult and juvenile fish facilities. Involved with this effort is the design, operation and evaluation of these projects to insure they are effectively bypassing fish. In 2014, PGE will be evaluating upstream passage of adult salmon and downstream passage of juvenile salmon as part of multi-year evaluations.	
PME Fish Resources	1,241,492
The Clackamas License requires PGE to evaluate temperature, habitat and mitigate for ecological function impacts related to the North Fork Hydrelectric complex. Evaluations of the Project Mitigation and Enhancement (PME) measures include spawning surveys, temperature monitoring, habitat evaluations, population monitoring, water quality monitoring and flow assessments.	
PME Terrestrial Resources	127,359
The Terrestrial Resource Management Plan (TRMP) is the principal instrument for management of, implementation, monitoring and adaptation of Protection Mitigation and Enhancement Measures for terrestrial resources affected by or related to the hydro Project.	

Total 2014 Budget - Westside Hydro Projects **$1,649,922**

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 262

Transmission & Distribution

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Bill Nicholson
Bruce Carpenter

February 15, 2013

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I. Introduction

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

A. My name is Bill Nicholson. I am Senior Vice President of Customer Service, Transmission and Distribution.

My name is Bruce Carpenter. I am Vice President of Distribution.

Our qualifications are included at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to explain PGE's 2014 test year Transmission and Distribution (T&D), operation and maintenance (O&M) expenses, and capital expenditures. We discuss how they support PGE's goal of operational excellence that incorporates improvement efforts and efficiency gains.

Q. What are the T&D group's primary goals in delivering customer service?

A. Our primary goals are to:

- Provide energy delivery services to our customers that are safe and reliable;
- Deploy new techniques and process improvements to improve efficiency and increase customer value;
- Cultivate a corporate culture that will improve employee safety; and
- Ensure compliance with new regulations for transmission grid reliability.

Q. Please summarize PGE's Transmission and Distribution O&M expenses and capital expenditures for 2011 actuals and the 2014 test year.

A. Table 1 below summarizes this information:

Table 1
Summary of T&D O&M Expenses and Capital Expenditures ($ Million)

	2011 Actuals	2014 Test Year
Transmission O&M Expenses	$ 11.5	$ 12.4
Transmission Capital Expenditures*	$ 14.1	$ 25.5
Distribution O&M Expenses	$ 81.6	$ 93.8
Distribution Capital Expenditures	$ 127.7	$ 175.6

*Capital expenditures for Cascade Crossing are presented in PGE confidential Exhibit 801.

The amount of capital expenditures that close to plant by year-end 2014 is reflected in rate base as presented in PGE Exhibit 300.

Q. PGE has initiated programs designed to improve the efficiency of PGE's Distribution operations. Which key programs will you discuss in your testimony?

A. PGE is undertaking a number of initiatives to improve overall quality of service delivery to our customers. Collectively, these initiatives are known as the 2020 Vision Program, discussed in PGE Exhibit 600. The Distribution-related programs under the 2020 Vision Program include:

- Work and Asset Management System Upgrades (Maximo, Mobile & Scheduling);
- Geospatial Information System and Graphic Work Design Applications (GIS/GWD) Replacement;
- Outage Management System (OMS) Replacement Program; and
- T&D Transformation.

We discuss O&M expenses and capital expenditures associated with these programs in Section IV of our testimony.

In Section II of our testimony, we discuss PGE's current and future efforts to improve its work practices and realize operational efficiencies.

Q. Please explain why PGE's Distribution O&M increases by approximately $12 million from 2011 to 2014.

A. The increase in Distribution O&M expenses is approximately evenly divided between labor-related expenses ($5.5 million – which is net of the full-time equivalent (FTE) reduction and wage escalation) and non-labor expenses ($5.8 million). The details of the non-labor increases are discussed in Section IV below, but approximately $4 million of the increase in Distribution non-labor O&M expenses can be attributed to PGE's 2020 Vision Program. The remainder of the increase in non-labor O&M expenses is explained by modest increases in PGE's programs for Tree Trimming, Locating, and Facility Inspections and Treatment to the National Electric Safety Code (FITNES). FITNES is our program to ensure that our power poles and underground (UG) facilities are inspected, treated, and maintained.

The increase in labor-related O&M expenses falls primarily in five areas: Meter Services, Customer Response, System Control Center, Substation Operations, and T&D Asset Management. The increases do not necessarily represent a net increase in expenses for the departments as they are offset in some cases by reductions in labor services that are charged to capital. PGE labor-related expenses are examined in PGE Exhibit 500.

Q. Please explain the decrease in T&D FTEs.

A. Despite the expected addition of 16,000 customers from 2011 to 2014, a projected increase in T&D assets, and new regulatory compliance requirements described below, FTEs for Transmission and Distribution are projected to decrease by approximately 37, mainly through process efficiency measures. This decrease is net of a projected increase of 14.5

FTEs for regulatory compliance. The 2014 test year includes 6 FTEs to meet requirements to provide intra-hourly transmission scheduling at 15-minute intervals as required by FERC Order No. 764. The 2014 budget also includes 4 FTEs to support PGE's Reliability Standards Enhancement Project, 3 FTEs to support PGE's response to the FERC/NERC Southwest Outage Report, and 1.5 FTEs to address other general compliance issues. These increases are explained in detail in Section III. From 2011 to 2014, total T&D wages and salaries are projected to increase at an annual average rate of 0.7 percent. FTEs and compensation are discussed in detail in PGE Exhibit 500.

Q. How is the remainder of your testimony organized?

A. In Section II, we discuss PGE's improvement efforts in PGE's Transmission and Distribution functions.

In Section III, we discuss Transmission O&M expenses and expenditures related to planned transmission capital work. Section III also includes a discussion of the projected increase in PGE's labor requirements due to the expansion of PGE's regulatory compliance requirements.

In Section IV, we provide an overview of Distribution O&M expenses and capital expenditures. In addition to the 2020 Vision Program, we discuss expense increases in the Tree Trimming, FITNES, and Locating programs.

Section V contains our qualifications.

II. Improvement Efforts and Efficiency

Q. What measures have you implemented to improve efficiency and effectiveness?

A. Within T&D, PGE is implementing multiple initiatives to improve efficiency and effectiveness through the T&D Transformation program. The specific measures are discussed below.

Q. What is the T&D Transformation Program?

A. The T&D Transformation program (T&D) is a subset of the 2020 Vision Program (see PGE Exhibit 600 Section II). Leveraging the large number of software replacements through the 2020 Vision Program, T&D reviewed opportunities to implement industry leading practices across the organization in order to fully capture the benefits of the new tools. The T&D program began in 2010 with an initial assessment to determine areas for focused improvement efforts in transmission and distribution. Through this assessment, five key areas of focus were agreed on:

- Employee Safety
- Accountability
- Process Standardization
- Productivity
- O&M Efficiency

A benchmarking effort, led by First Quartile Consulting, was initiated soon after the program's assessment phase as part of the corporate-wide effort to foster improvement efforts through routine benchmarking. The benchmark solidified the project's focus areas and provided insight into industry best practices. In a majority of areas of T&D,

benchmarking determined that PGE was within the first or second quartile in terms of effectiveness and efficiency.

Q. Please describe how the T&D program is implemented.

A. The T&D program is based upon the principles of centralization, standardization and integration (CSI). Processes and operating units are first centralized and standardized. Then technology is integrated where possible to streamline workflow and automate processes.

Q. What process improvements are projected through 2014?

A. For T&D Transformation, we expect several process improvements, including the following:

- Consolidation of regional line dispatch
- Centralization of service coordination
- Supervisor in the Field
- Introduction of Off-Shift Crews
- Optimization of fleet assets
- Asset Management
- Other field improvements

Q. What is included in consolidation of regional line dispatch?

A. Consolidation of regional line dispatch involves reorganization from a regional to a functional organization. All regional dispatchers (Southern, Western and Eastern), who are responsible for dispatching work to our line crews, were consolidated from five locations into one work location. With a single company-wide dispatch group, PGE is better positioned to prioritize work and reduce crew miles driven allowing for more efficient work scheduling.

Q. What does centralization of service coordination entail?

A. Centralization of service coordination involves consolidating service coordinators and customer contact functions for the Tree-Trimming and Power Quality groups into a single location at the Tualatin Contact Center (TCC). Consolidation allows for standardization of work practices and better coverage of the phone and email contact workload. Customers benefit through a more consistent experience.

Q. What will the Supervisor in the Field initiative accomplish?

A. Supervisor in the Field (SITF) is an initiative focused on promoting employee safety, efficiency and standardized processes by increasing the time General Foremen (GF) spend on jobsites with field crews. For example, the GF will ensure the work is being done in a safe and efficient manner to meet all customer commitments, providing necessary equipment and labor resources and helping to resolve construction issues that arise. With aspects of each job more organized, the crew will be able to more efficiently and safely complete jobs, resulting in reduced overtime and more successfully completed tasks per day. T&D has committed to a 3- to 5-year program to reduce O&M overtime expenses by 40 percent in substation maintenance and technician work through better work coordination and scheduling.

Q. What is the goal of the Off-Shift Crew work practices?

A. The Off-Shift Crew initiative creates crews that are available during evenings and throughout the weekend. Evenings and weekends are known as "off-shift" scheduling times. By having crews available during off-shift hours, PGE increases its effectiveness and efficiency by having a faster response time and by reducing costly overtime expenses. Instead of calling in-line crews after they have left work for the day, a crew is already on-shift and ready to resolve situations that arise. This allows PGE to achieve a faster response time during off-shift hours. Further, instead of paying overtime expense for day-shift line crews to continue working beyond the end of their shift or come back to work, many off-shift jobs are now handled by crews compensated at straight-time labor wages. Customers benefit from a faster response time, combined with the convenience of increased availability of planned maintenance shutdowns occurring during off-shift hours.

Q. What does optimization of fleet assets involve?

A. Fleet optimization involves finding the right combination of new, repurposed and rented assets to support PGE's operational needs. Optimization also includes the benefits of an inventory partnership with NAPA Integrated Business Solutions, which reduces the cost of inventory management and increases productivity of maintaining fleet assets.

Q. What is Asset Management?

A. Asset Management is the practice of making asset maintenance and replacement decisions that optimize the balance of asset performance and costs to support our goal of providing customers with safe, reliable power at a reasonable cost. This is achieved by determining what risks are allowable and acceptable within our system to meet customer expectations, and then making asset maintenance/replacement decisions that align with and support established risk thresholds.

Q. Why is PGE pursuing Asset Management?

A. Asset management is the primary route for asset-intensive industries to achieve an optimal balance of performance and costs. Two fundamental goals exist for our program:

1) holding steady or increasing system reliability while optimizing O&M costs; and 2) holding steady or increasing long-term system reliability while ensuring capital investment is properly targeted.

Q. What is the expected time frame to reach T&D's asset management goals?

A. Creation of a fully mature asset management program is expected to take ten to fifteen years. Initially, over the next three to five years, we will aggressively build and refine the strategic infrastructure and processes needed for the program to be successful. Initiatives underway include finalizing an asset management policy, developing program performance goals, and creating a uniform method to assess asset criticality. Additional work to be done this year includes developing a preliminary approach to measuring the cost of reliability and developing risk thresholds for selected asset classes

Q. What will other field improvements contribute?

A. Other field improvements include cost savings from a number of smaller projects that focus on improving employee safety and efficiency, such as Safe and Efficient Design Construction (SEDC) projects, which are created and prioritized by T&D teams in the field based on their ability to promote employee safety and efficiency. For example, the Substation Shutdown Planning Improvement involves the improvement of planning in scheduled substation maintenance activities. This will reduce the time it takes to complete maintenance activities by decreasing mobilization and travel costs and increasing crew efficiency. Another SEDC project is the Super Crew initiative, which combines the hole digging and line crew functions to facilitate a more effective, efficient, and safe method of framing poles when possible. By combining crews, the number of times a hole digger crew must visit a job site is reduced. In addition, Utility Asset Management (UAM) has worked with joint-use customers to establish agreements to temporarily transfer their equipment to a newly set pole, therefore eliminating the need for a crew to return to a job site again to pull a pole after all joint-use licenses have transferred. Joint-use customers are entities, such as telecommunication companies, that place attachments on PGE's utility poles.

The number of trips required to frame a pole that fits the criteria for this method is reduced on average from 3 to 1. The new procedure reduces the overall capital time and expense required to frame a pole. T&D is also standardizing the framing process company-wide (where possible), so that framing poles is now handled more often on the ground. By framing poles on the ground, PGE can increase employee safety and reduce injuries associated with framing poles in the air.

Q. What technology has been implemented and which T&D employees are affected?

A. The first phase of technology, rolled out in the fourth quarter of 2012, affects Substation Operations, most T&D single field employees, and associated office support via the implementation of software, including:

- Enterprise work and asset management software (Maximo) that enables consistent and comprehensive tracking of work and assets.
- Enterprise Resource Management (Logica's Asset and Resource Management (ARM) Scheduler and Field Manager), which integrates with Maximo and other work systems, to be used in scheduling, dispatching and updating field work.
- The second phase roll-out will deploy these same tools to other employee groups within T&D such as line crews and joint-use employees.

Q. What are the benefits of Phase 1 implementation?

A. Maximo, Mobile & Scheduling will improve employee safety, heighten accountability, and standardize our processes, which will improve productivity and efficiency.

- Employee Safety: With mobile devices in the hands of field workers, work processes have a set of dynamic steps that must be performed and logged when a worker is completing an inspection or doing maintenance work. The Mobile & Scheduling tools also heighten employee safety by providing another communication channel in the field. For example, employees can send out "Jeopardy Alerts," which are designed to draw attention to events that may impact work schedules.
- Accountability: Maximo, Mobile & Scheduling provides teams with better information to help continually improve the business. Supervisors have the ability to review the current status of field crews and details of assigned work. Field workers can update the status of their work, resulting in real-time data for schedulers and supervisors. By having an enterprise-wide work and asset management system, we will have a clearer, more integrated view of how work is performed within PGE and how to more effectively use our company assets.
- Productivity: PGE will improve productivity as work orders will be created in Maximo, routed to the closest available resource with the correct skillset, and be dispatched to the field workers (including contractors) electronically. The new technology allows us to provide workers with real-time customer and asset information. Specifically, Maximo provides the ability to plan inventory to meet maintenance precisely. Mobile & Scheduling provide:
    - Optimization of scheduling to reduce travel time and crew costs.

- The opportunity to re-optimize work schedules dynamically as needed.
- Real-time dispatching of work details and status updates.
- Automatic asset information updates and work order closure.

- Efficiency: Maximo provides PGE with the ability to track inventory use to find optimum stock levels. The goal is to maximize availability of items for upcoming work while also reducing unnecessary inventory and associated carrying costs. It also allows us to track purchasing of inventory stores and materials for work orders.

Q. What cost efficiencies are projected in the test year from T&D Transformation?

A. We project annual O&M savings of $3.4 million in 2014, mainly attributable to Supervisor in the Field, the Off-Shift Crew program, and Regional Dispatch improvements. As our operational efficiency initiatives develop, we also expect savings to accrue for capital projects.

III. Transmission

A. Transmission O&M Expenses

Q. Have transmission non-labor O&M costs increased materially from 2011 to the 2014 test year forecast?

A. No. Transmission non-labor O&M expenses are virtually flat from 2011 to 2014.

Q. Have transmission labor O&M costs increased from 2011 to the 2014 test year forecast?

A. Yes. Transmission labor O&M expenses have increased by approximately $1 million from 2011 to 2014.

Q. What accounts for the $1 million increase in Transmission labor O&M expenses?

A. As mentioned in Section I, PGE is experiencing increased requirements for compliance with regulatory standards.

Q. Please describe the increased compliance obligations that affect Transmission operations.

A. Since 2011, new rules and regulations from the Federal Energy Regulatory Commission (FERC), North American Electric Reliability Corporation (NERC), and Western Electricity Coordinating Council (WECC) have required us to hire additional FTEs. Specifically, these new regulatory obligations include the following areas:

- FERC Order No. 764, issued on June 22, 2012, as affirmed and clarified by Order No. 764-A, issued December 20, 2012, is intended to facilitate the integration of variable energy generation (such as wind and solar generation) into the transmission system. The Order requires PGE and other public utility transmission providers to amend their Open Access Transmission Tariffs (OATT) to allow transmission customers to schedule transmission at fifteen-minute intervals. PGE must implement this Order by November 12, 2013.

- In April, 2012, FERC and NERC published a report regarding the causes of a September 8, 2011, blackout that affected 2.7 million customers in Arizona and Southern California.[1] The report found that weaknesses on the part of several utilities in the two broad areas of operations planning and real-time situational awareness contributed to the outages. The report included 27 recommendations to the industry to help prevent similar outages.
- The number and scope of NERC Reliability Standards continue to increase. In addition, NERC and WECC have increased their scrutiny of the compliance programs implemented by the owners, users, and operators of the bulk electric system. Through its development and deployment of the Internal Compliance Program Assessment tool, WECC has indicated that its evaluation of an entity's compliance program will have a significant effect on how it addresses any potential violations by that entity. In addition, NERC has indicated that it plans to direct WECC and the other Regional Entities to transition to a risk-based enforcement approach in which the scope and duration of their enforcement activities is contingent (in part) on an entity's compliance program.

While these are significant FERC, NERC and WECC regulatory initiatives affecting the utility industry, they are not inclusive of all new requirements.

[1] *Arizona-Southern California Outages on September 8, 2011: Causes and Recommendations*

Q. How is PGE responding to these increased regulatory obligations?

A. PGE's FERC Compliance Department, legal department, and its affected operating units are all actively engaged in monitoring FERC, NERC and WECC regulatory activities and are preparing to address new regulatory requirements in a prudent manner. Some ways that PGE is addressing new regulatory obligations are:

- Order No. 764: PGE currently offers transmission scheduling on an hourly basis, with limited intra-hour scheduling on a thirty-minute basis (at the bottom of the hour). In order to meet the operational requirements of offering fifteen-minute scheduling, PGE is planning to add transmission schedulers for 24/7 real-time operations. The transmission schedulers will participate in nearly continuous scheduling activities throughout each hour, allowing the balancing authority operators to devote their full attention to maintaining the reliability of the bulk electric system. As indicated in Section I above, this will necessitate the addition of six FTEs in order to provide for one transmission scheduler on duty around the clock.
- Arizona/Southern California Outage Report: After this report was issued in May 2012, PGE convened an interdepartmental task force to assess the report's 27 recommendations and their applicability to PGE. As a result of this assessment, PGE determined that it needed to increase its capabilities in the areas of next-day planning and real-time situational awareness in order to meet the increased expectations of FERC and NERC. Consequently, PGE identified three Transmission Operations Engineer positions that need to be added to T&D.

- Reliability Standards Compliance: PGE recently undertook a review of the way the company has structured its reliability standards compliance program. As a result of this review, PGE determined that it needs to strengthen its compliance program to ensure that the reliability standards requirements are met. In particular, in addition to identifying a Requirement Owner for each requirement, who is responsible for complying with that requirement, PGE now believes it is also necessary to identify a backup who shares compliance and documentation responsibility for each requirement. We also determined that all evidence of compliance should undergo an additional technical review process to ensure that PGE is in compliance with these highly technical requirements.

PGE identified a total of four FTEs that were needed to support this higher level of compliance. Two of these FTEs are budgeted for the system control center to assist with compliance for the transmission operator and balancing authority function. Two additional FTEs are budgeted for the system protection area to assist with compliance for the generator owner, transmission owner, and other functions.

These initiatives do not include PGE's compliance efforts for the NERC Critical Infrastructure Protection (CIP) Standards. Incremental costs associated with a potential new version of the CIP Standards are addressed in PGE Exhibit 600.

B. Transmission Capital

Q. What transmission-related capital work is PGE planning before the end of the 2014 test year?

A. PGE is continuing its work on the Capacity Expansion Project.

Q. Please describe the Capacity Expansion Project.

A. PGE's Capacity Expansion Project is a multi-year project to address system needs by expanding and upgrading PGE's transmission system. This project is being implemented to comply with NERC regulations and to provide capacity for continuing area load growth. Capacity Expansion Project capital expenditures for 2014 make up the bulk of transmission capital expenditures in 2014. In 2014, PGE will acquire Shute/Sewell property easements in Hillsboro and construct the Shute Substation. This substation provides distribution capacity needed to support growth in the region.

IV. Distribution

A. Distribution O&M Expenses

Q. Please identify the changes in Distribution non-labor O&M costs from 2011 to 2014.

A. Distribution non-labor O&M expenses (net of corporate transfers) increase from approximately $29.8 million to $35.6 million, an increase of approximately $5.8 million.

Q. What are the non-labor factors that increase Distribution O&M expenses?

A. Table 2 below reports the major drivers of increased non-labor O&M expenses in Distribution:

Table 2
Distribution Non-Labor O&M Drivers of Cost Changes from 2011 to 2014 Test Year Forecast ($ Million)

Cost Driver	2014-2011
2020 Vision Program/T&D Transformation	$ 4.0
Tree Trimming	$ 0.9
FITNES Program	$ 0.4
Locating Cost Increases	$ 0.2
Total of Non-Labor Cost Drivers from 2011 to 2014	**$ 5.5**

We discuss each of these drivers in more detail below.

1. 2020 Vision Program

Q. What is the 2020 Vision Program?

A. The 2020 Vision Program is a long-term initiative to consolidate and modernize PGE's technology infrastructure and work processes to ensure that PGE can continue to meet the changing needs of both the company and our customers. This program is discussed in more detail in PGE Exhibit 600.

Q. What increases in distribution expenses fall under the 2020 Vision Program?

A. There are four main areas:

- Phase 2 Maximo, Mobile & Scheduling.

- Geospatial Information System and Graphic Work Design Applications (GIS/GWD) Replacement.
- Outage Management System (OMS) Replacement Project.
- Other T&D Transformation Expenses.

Q. In Section II, you discussed Maximo, Mobile & Scheduling and T&D Transformation at length. Please describe the GIS/GWD replacement program and the OMS replacement program.

A. The GIS/GWD replacement program will analyze, design, build, test and deploy the Geospatial Information System and Graphic Work Design applications. The program evaluates software and selects graphic work design tools that provide enterprise-level functionality. Under this program, PGE will retire legacy applications and consolidate to an enterprise-wide GIS and GWD tool set.

The OMS replacement program will analyze, design, build, test and deploy a new outage management system. It will define and implement up-to-date business processes and system requirements, replacing an in-house developed application with a modern, vendor-supported application. OMS will make use of real-time smart grid data to proactively alert PGE and its customers of outage information, improve real-time information before and during outages, and integrate with PGE's Automated Vehicle Locating system to efficiently dispatch crews and improve outage response time.

Q. Please summarize the increases between 2011 and 2014 in non-labor O&M expenses due to the 2020 Vision Program.

A. The increases in non-labor O&M expenses are shown below in Table 3.

Table 3
Increases in 2020 Vision Program Non-Labor O&M Expenses for 2014 Test Year
($ Million)

	2014 - 2011
Maximo Phase 2 - Mobile & Scheduling	$ 1.7
GIS/GWD Replacement	$ 0.9
OMS Replacement	$ 1.6
Other T&D Transformation Expenses	$ (0.2)
Total	$ 4.0

The capital requirements for the 2020 Vision Program are discussed in Section IV, Part B.

2. Tree Trimming

Q. What is PGE's current practice with respect to tree trimming cycles?

A. PGE's practice is a two-year cycle in urban areas and a three-year cycle in rural areas.

Q. How do you estimate tree trimming costs for 2014?

A. PGE first determined the number of crews necessary to complete the work to meet the requirements of Oregon Administrative Rule (OAR) 860-024-0016 and to complete the program descriptions contained in PGE's service quality measure (SQM) reports, and then applied the contract labor rates for the crews to determine total costs.

For the work in 2014, we forecast a need for 36 tree trimming bucket crews, two sub-transmission trimming crews, three back-lot trimming crews, two one-person response crews, and one cross-country right-of-way climbing/clearing crew.

Q. Comparing 2011 to 2014, are the amount of work and the number of contract crews expected to be similar?

A. Yes.

Q. If the amount of work and contract crews remains the same, why are tree trimming non-labor costs projected to be higher by approximately $0.9 million in 2014?

A. The increase is due to the higher rates in a new union contract. In 2012, Asplundh Tree Experts and IBEW Local 125 negotiated a new 3-year contract. The outcome was higher wages for union employees. For PGE, which uses Asplundh, the rate for a standard two-person trimming crew will increase approximately 2.2 percent per year. The annual percentage increase in total tree trimming costs from 2011 to 2014 is also approximately 2.2 percent per year.

3. Facility Inspection and Treatment to the National Electric Safety Code (FITNES)

Q. Please describe PGE's FITNES program.

A. The FITNES Program includes the inspection, maintenance, and repair of poles and overhead (OH) distribution and transmission facilities on approximately 270,000 wood poles on a ten-year cycle, and all of our underground (UG) equipment (approximately 93,000 total UG units) on a ten-year cycle, including PGE equipment located on large industrial campuses.

Since PGE launched the FITNES Program in 1987, poles needing to be replaced due to decay have declined from 12 percent per year to less than 1 percent per year, saving millions of dollars in replacement costs. This important preventative maintenance extends equipment life, reduces costs, and increases employee safety. In addition, FITNES identifies potential public safety issues and resolves them before they cause outages or other hazards.

Beginning in 2011, the underground portion of the FITNES program transitioned from the existing four-year cycle to a ten-year cycle (2008-2017). Under a ten-year cycle, PGE plans to inspect an average of 9,300 underground units per year. By end of 2011 (four years into the current cycle), PGE had completed inspections on 47,314 UG units, which is more than 50 percent of the total UG units.

Q. Why are non-labor costs projected for 2014 approximately $400,000 greater than 2011?

A. In 2011, a majority of the FITNES Program repair work was performed using existing PGE line crew labor due to the economic downtown. The 2014 FITNES Program budget assumes a return to more normal economic conditions and a transition back to using contract line crews to perform a larger proportion of the FITNES Program repair work. This transition accounts for a majority of the increase projected for 2014 non-labor costs.

4. <u>Underground Utility Locating ("Locating")</u>

Q. Why are costs increasing by approximately $200,000 for locating?

A. The number of locate requests is forecast to increase in 2014. We explain these factors below. The annual rate of increase in total costs of locating is approximately 5 percent, reflecting the increase in the number of locates in 2014 relative to 2011.

a. Locating Contract Costs

Q. Are contractor costs increasing?

A. No. PGE's locating contract was renewed in June, 2012. As part of the negotiations, the contractor's rates decreased by 9.2 percent. This contract is bid on a unit-price basis and we have tracked the average cost per locate since 1991.

Q. How does PGE's current cost per locate compare to 1991?

A. PGE is paying less per locate today than in 1991; approximately 11 percent less per locate, unadjusted for inflation. When adjusted for inflation, PGE is paying approximately 47 percent less per locate than in 1991.

b. Locating Requests ("Locates")

Q. How does PGE forecast the number of locates for the 2014 test year?

A. PGE considers actual numbers of locates for the last three to five years as well as current trending to forecast the anticipated number of locates for 2014. Over the three-year period 2009-2011, there was an average decline in locates of 5.6 percent. Over the five-year period 2007-2011, there was an average decline in locates of 2.1 percent. Some of the decline can be attributed to process improvements that PGE has made such as reducing the overall area in which PGE receives a request to locate. But some of the decline can also be attributed to the state of the economy. The decline would have been even greater had it not been offset by an increased number of people calling due to the Call 811 public awareness campaign. This declining trend has reversed, however, and PGE experienced a 10.3 percent rise in the number of locates from 2011 to 2012.

Q. Why does PGE expect the number of locates to increase in 2014?

A. There are two reasons. First, greater public awareness results in more locate requests. The latest survey by CGA shows that public awareness about the need to call-before-you-dig has increased by 29 percent since 2008. With educational efforts continuing into the future, we expect to see a continuing increase in the percentage of people calling for locate requests. Second, the economy is recovering and this is reflected in the increase in locates requested in 2012.

Q. What is PGE's forecast of locate requests for the 2014 test year?

A. As indicated above, PGE experienced a 10.3 percent rise in the number of locates from 2011 to 2012, for a total of 126,437 locates in 2012. Due to the recent reversal in trend, we estimate a 3 percent growth rate for 2013 and 2014. This reflects historical averages and accounts for current trending. The majority of the forecasted increase from 2011 to 2014, however, is accounted for by the increase already observed for 2012.

B. Distribution Capital

Q. What distribution-related capital work is PGE planning that affects the 2014 test year?

A. As part of its 2020 Vision Project, PGE is planning 3 major capital distribution projects:

- Maximo Phase 2 - Mobile & Scheduling;
- GIS/GWD Replacement; and
- OMS Replacement.

Table 4, below, summarizes the capital expenditures for these projects for 2011 through 2014 discussed in more detail above:

Table 4
Distribution Capital Expenditures ($ Million)[2]

	2011 Actuals	2012 Forecast	2013 Budget	2014 Test Year
Maximo Phase 2 - Mobile & Scheduling	-	-	$ 11.1	$ 17.2
GIS/GWD Replacement	-	-	$ 6.6	$ 8.8
OMS Replacement	-	-	-	$ 10.0
Distribution Base Business	$ 122.6	$ 130.0	$ 142.7	$ 139.6
Total	$ 122.6	$ 130.0	$ 160.4	$ 175.6

Q. Please describe the 2014 capital expenditures for the Maximo Phase 2 - Mobile & Scheduling project.

A. This project will include replacing Logica's Work Management System (WMS) for T&D and converting some existing Visual Basic 6 asset databases and applications (a dated and unsupported platform) to Maximo.

Q. Please describe the 2014 capital expenditures for the GIS/GWD Replacement project.

[2] The capital amounts in the table represent capital expenditures for the year. The amounts that represent plant in rate base are presented in PGE Exhibit 300.

A. The scope of the project includes:

- Development of project plans for GIS and GWD.
- GIS, GWD, and Mobile GIS implementation related work.
- Cleanup and Conversion of current GIS data.
- Conflation (spatial adjustment) of land/data to a prescribed standard.
- Conversion of GIS-related Portland Underground Core records.
- Implementation and integration of advanced underground duct management applications.
- Implementation and integration of advanced fiber optic management applications.

Q. Please describe the 2014 capital expenditures for the OMS Replacement project.

A. This project procures and implements a new Outage Management System (OMS) with increased functionality, including a graphical user display and switch management capabilities. This replaces the current PGE-developed OMS system that runs on an unsupported platform.

C. Distribution Service Quality

Q. Does PGE provide service quality reports to the OPUC at the Distribution level?

A. Yes. PGE submits annual service quality measure (SQM) reports, which contain outage and other results. The Commission Staff reviews our SQM reports for compliance with defined performance levels. Provided in PGE's SQM reports are PGE's annual results of its System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), and Momentary Average Interruption Frequency Index (MAIFI).

Q. What are SAIDI, SAIFI and MAIFI?

A. SAIDI is the total time during a year the average customer is without power, measured in minutes. SAIFI is the average number of times a customer experiences an outage during a one-year time period. MAIFI is the average number of momentary outages a customer experiences during a one-year time period.

Q. Has PGE been meeting its requirements for SAIDI, SAIFI and MAIFI?

Yes. As shown in Table 5 below, for 2010 through 2012, PGE's results were well within the thresholds established by the OPUC. PGE's three-year weighted averages (2010 through 2012) for all three measures also fall well below the OPUC penalty thresholds.

Table 5
Three-year Weighted Averages and Penalty Threshold Limits

Year	SAIDI (minutes)	SAIFI (occurrences)	MAIFI (occurrences)
2012	72	0.55	1.11
2011	66	0.51	0.89
2010	77	0.65	1.1
3-Year Weighted Average	**71.2**	**0.56**	**1.04**
OPUC Level 1 Penalty Threshold	105	1.2	5

V. Qualifications

Q. Mr. Nicholson, please describe your educational background and qualifications.

A. I received a Bachelor of Science Degree in Nuclear Engineering from Oregon State University. I completed the Harvard University Program on Negotiation and graduated from the Public Utilities Executive course at the University of Idaho. I am a registered professional engineer in the State of Oregon and I belong to the American Society of Mechanical Engineers and the National Society of Professional Engineers. My employment with PGE started in 1980 as an engineer at the Trojan Plant and I have served in a variety of capacities in Distribution Operations, Generation Engineering and Resource Development. In May 2007, I became Vice President of Customers & Economic Development and in August of 2009, I was appointed Vice President of Distribution. In April of 2011 I assumed my current role as Senior Vice President of Customer Service and Delivery, Transmission and Distribution.

Q. Mr. Carpenter, please describe your educational background and qualifications.

A. I received a bachelor's degree in business from Southern Oregon State College and an MBA from Oregon State University. I completed the Edison Electric Institute senior middle management course in 1987. My employment with PGE started in 1979 as an internal auditor and I have served in a variety of capacities in distribution, rates & regulatory affairs, operations planning, generation, finance, and customer service. In August 2009, I was appointed Vice President of Distribution Services and in January of 2012 appointed Vice President of Distribution.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
801C	T&D Transmission Expenditures

Exhibit 801C

Confidential

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 262

Customer Service

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Kristin Stathis
Carol Dillin

February 15, 2013

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I. Introduction

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

A. My name is Kristin Stathis. I am Vice President of Customer Service Operations.

My name is Carol Dillin. I am Vice President of Customer Strategies and Business Development.

Our qualifications appear in Section IV of our testimony.

Q. What is the purpose of your testimony?

A. We will discuss various improvement initiatives that PGE has completed and is undertaking in the near term to continue providing excellent customer service, achieve operational efficiencies, and enhance Customer Service offerings. We will also describe our plan to respond to changing customer expectations. As part of our testimony, we also explain PGE's Customer Service operations and maintenance (O&M) expenses for the 2014 test year[1].

Q. How is your testimony organized?

A. We begin with a brief overview of PGE's Customer Service operations. As part of that overview, we discuss customer feedback and PGE's response, including what PGE has accomplished and what PGE plans to achieve in the near term. Additionally, PGE Exhibit 901 contains a summary of the results of a recent benchmarking study in which PGE participated as part of its efforts surrounding efficiency and effectiveness. Also, as part of the overview, we discuss the costs associated with PGE's Customer Service and related O&M expenses for the 2014 test year. In Section III, we discuss how PGE will meet

[1] Calculated Customer Expenses are consistent with FERC Chart of Accounts categories Customer Accounts Expenses and Customer Service and Informational Expenses (901-910).

customers' expectations in the long term, specifically with PGE's Customer Engagement Transformation (CET) program. Also in Section III, we discuss moving forward on PGE's smart grid roadmap, and share our proposal for a "no fee" bank card program. We conclude with our qualifications.

II. Customer Service Overview

Q. What is PGE's Customer Service mission?

A. PGE's mission for Customer Service is to deliver value to our customers by providing excellent service at a reasonable price. PGE achieves this through operational excellence and listening and responding to the needs and expectations of our customers.

Q. Please describe PGE's Customer Service.

A. PGE's Customer Service organization provides service to our customers in a variety of ways. PGE offers customers many options for doing business with us; through our contact center, at our community offices, through self-service[2] customer channels[3] such as the web, mobile and IVR[4], and by working directly with customers in their homes and places of business. Operationally, Customer Service activities include metering and billing, payment processing, and management of receivables. Strategically, Customer Service activities include research and collecting direct feedback, listening to our customers' expectations and developing and delivering products and services that best meet their needs.

A. What Our Customers Tell Us

Q. How does PGE determine whether it is accomplishing its mission for Customer Service?

A. PGE determines whether it is accomplishing its mission primarily by listening to feedback gathered directly from its customers.

[2] "Self-service" refers to a customer's ability to conduct a transaction on his or her own, without needing to speak to a company representative.
[3] "Customer channel" refers to a method of customer interaction chosen by customers based on what services are available through that channel. For example, web, payment centers, and community offices are all examples of distinct customer channels for payment.
[4] IVR refers to Interactive Voice Response, a call center technology that allows customers to use touch tone telephones to interact with computer systems.

Q. Describe PGE's continuing process of surveying customer satisfaction.

A. PGE has contracted with Market Strategies International ("MSI"), an independent full-service customer market research company headquartered in Michigan, to conduct quarterly and bi-annual customer satisfaction surveys with PGE's residential and general business customers since 1995. According to the fourth-quarter 2012 MSI survey, PGE received a positive rating on overall satisfaction for residential and business customers, placing its performance in the top decile of its peer utilities.

Since 2005, PGE has contracted with TQS Research, Inc. (TQS), an independent market research firm, to conduct annual customer satisfaction surveys with its largest customers. TQS, headquartered in Georgia, specializes in business-to-business research among the largest energy users in the United States and Canada. PGE ranked second nationally in overall customer satisfaction and number one in reliability with large key customers, placing in the top decile among electric utility holding companies in the 2012 TQS Research, Inc. survey results.

In addition, PGE also acquires the results of the annual J.D. Power and Associates Electric Utility Customer Satisfaction Study℠ (J.D. Power Study) for both residential and general business customers. PGE uses the J.D. Power Study primarily as a benchmark to other electric utilities. PGE was ranked as the top investor-owned utility in the nation for residential customer satisfaction and number two among large utilities in the West for business customer satisfaction by J.D. Power & Associates in 2012.

Q. Describe other ways that PGE gathers feedback from customers.

A. PGE also collects customer feedback on transactions through PGE's website, in community offices, and in its call center. Occasionally, PGE holds customer focus groups to gather feedback on specific topics. This feedback is used to improve PGE's service and identify customer interest in new services and offerings.

Q. What have you learned from your customers' feedback?

A. PGE's customer research and feedback has demonstrated that, while PGE has done a good job meeting customer expectations in the past, customer expectations are changing. Specifically:

- Our customers expect to transact business with and receive information from PGE when they want, through their preferred channel.
- As a utility, customers expect PGE to deliver innovative programs, technologies and solutions, such as pricing options and energy management tools, which are enabled by insight gained from their usage data and will help them control their own energy use and costs.
- Customers want to engage in a simple, satisfying customer experience with PGE employees who are well-equipped to answer questions and resolve issues in a timely manner.
- Customers want to know that PGE understands their preferences, because PGE's employees are able to access information from their past interactions across multiple channels.
- Customers want reasonable prices.

In addition to what PGE has heard from customer feedback, PGE has also observed a change in how customers have chosen to interact with us. PGE Exhibit 902 illustrates how customers' preferences have shifted to self-service and electronic interactions over the last several years, mirroring the experience of the broader consumer marketplace.

B. PGE's Response to Our Customers' Changing Expectations

Q. How is PGE responding to customer feedback?

A. PGE uses feedback it has collected from customers to develop products and services that best meet our customers' needs. For example, our customers tell us their preferences for how and when they want to conduct business with us, and PGE responds by offering information and features through its web site, mobile presence, and IVR. Our customers tell us they're interested in innovative solutions and PGE responds by delivering value-driven products and services, such as the online energy management tool, Energy Tracker. Customers tell us they want their transactions with PGE to be simple and convenient and PGE responds by expanding its self-service options. The Customer Service improvement initiatives completed and currently underway demonstrate PGE's commitment to listen and respond to our customers.

Q. Please briefly describe some of the recent improvements PGE has made for customers.

A. PGE has implemented projects to improve service and increase efficiency. A few examples are:

- Energy assistance agencies asked PGE to help them reduce the amount of time they spend on the phone with call center representatives. In response, PGE created an online agency portal that allows agencies access to the necessary PGE customer information required to authorize assistance payments. As a result, PGE has seen reductions in the number and length of calls from agencies, and eligible customers now move through the energy assistance process more quickly.

- PGE provides customers with the option to receive mobile text and email alerts when their bill is due or their payment has been received. Our customers can report outages and receive outage updates online and via text messaging.
- PGE offers an online outage map on its website providing customers with nearly real-time outage information.
- PGE has launched Energy Tracker, a web-based application (accessed via the portlandgeneral.com website) to help customers manage their energy usage and control costs.
- Our customers asked to select the date their PGE bill is due and PGE responded with the Preferred Due Date billing option.
- PGE has reduced the time required to process a "stop" service request via the web by automating the resulting manual process.
- PGE's Print and Mail Services department now has Intelligent Barcode technology that lowered mailing costs and saved $50,000 annually.
- PGE is implementing new cash remittance processing software. PGE has negotiated a reduced maintenance cost, and will realize an annual savings of $90,000.

Q. Can you briefly describe some of the improvements you're planning to make in the near future for customers?

A. Yes. Prior to 2014, PGE expects to implement more service improvements based on our customers' feedback. For example:

- PGE will expand mobile text and email alert options to property managers to provide alerts when tenants "start" or "stop" electric service.

- PGE will enhance the Energy Tracker web application. Customers will be able to receive proactive email alerts indicating how much energy they have used within their billing period to help them budget and conserve energy.
- PGE is increasing its self-service options by offering payment extensions over the IVR and web so that customers in good credit standing will be able to extend the due date of their next payment without talking to a Customer Service Representative.
- PGE will eliminate the need for customers to call back with a confirmation number when making payments to avoid disconnection.
- PGE will improve its paperless billing program. The experience of receiving a paperless bill[5] will be improved by an updated e-mail notification and easy access to the information contained in PGE's customer bill inserts (currently not included in paperless bills).
- PGE will reduce the time required to process "start" and "move" service requests via the web by automating the resulting manual process.

C. Customer Service Cost Overview

Q. Does PGE expect Customer Service costs to increase in 2014 over 2011 in order to meet the business strategies, goals and objectives for Customer Service?

A. Yes.

Q. Please explain the increase in Customer Service costs from 2011 to the 2014.

A. Customer Service O&M expenses (excluding uncollectible expenses) increase from approximately $57.9 million to $72.1 million; or by approximately $14.2 million. However,

[5] PGE's paperless bill program provides customers with the option to receive an email each month letting them know that their electric bill has been posted online, in lieu of a paper bill.

uncollectible expenses are expected to decrease from $10.2 million to $9.3 million. Labor costs are projected to increase by approximately $2.3 million due to an increase in FTEs and wage escalation (discussed in PGE Exhibit 500). Non-labor expenses increase by approximately $6.8 million and IT costs increase by approximately $5.1 million. The primary driver of the increases in FTEs is implementation of the Customer Engagement Transformation (CET) initiatives, discussed in Section III below. CET O&M costs in 2014 are expected to be approximately $8 million. Non-labor costs also increase due to CET efforts plus the new "no fee" bank card payment proposal. The proposed "no fee" bank card proposal is expected to cost $1.6 million in O&M in 2014. IT cost increases are explained in PGE Exhibit 600. Table 1 below summarizes these expenses.

Table 1
Customer Service O&M Expenses ($Millions) and FTEs

Category	2011 Actuals	2014 Forecast	Delta
Labor	$24.3	$26.6	$2.3
Non-Labor	21.1	27.9	6.8
IT (direct and allocated)	12.5	17.6	5.1
Uncollectibles	10.2	9.3	(0.9)
Total Costs	**$68.1**	**$81.3**	**$13.3**
FTEs	**409.4**	**422.7**	**13.3**

The next section of our testimony discusses in detail, the Customer Engagement Transformation initiatives, Smart Grid, as well as the "no fee" bank card proposal.

III. Improvements 2014 and Beyond

Q. How will PGE meet customers' needs in the future?

A. As previously mentioned, PGE is seeing changes in the way our customers want to do business with us, driven by technology such as mobile devices. In addition, PGE's deployment of smart meters and the expected build-out of smart grid infrastructure present significant opportunities and challenges. For example, PGE's current customer systems have served customers well for many years; however, they have become technically and functionally obsolete, are not suited for emerging smart grid requirements and changing customer expectations, and must be replaced if PGE is to remain responsive to customers' needs, expectations, and preferences. In order to maximize the opportunity presented by system replacements, it is essential that PGE put in place best-practice business processes to capture efficiencies and deliver the most value for customers. For these reasons, PGE is implementing the Customer Engagement Transformation program.

Q. Please describe the Customer Engagement Transformation program.

A. The Customer Engagement Transformation (CET) program is a set of initiatives targeted specifically at the Customer Service functional areas. The CET program includes both large and small initiatives that focus on process improvements, business strategies, operational efficiencies, employee development, and replacement of PGE's Customer Information System (CIS) and Meter Data Management System (MDMS). Modern customer systems support the capabilities that are desired by our customers, the products and services enabled by the smart grid, and address efficiency improvements by automating manual processes.

To take advantage of the opportunities presented by new systems, and to maximize the benefits of these new systems, PGE plans to take an integrated approach to the CET program by implementing people, process and technology initiatives. PGE has had considerable success using this approach with the implementation of two large systems already: Advanced Metering Infrastructure (AMI) and Financial System Replacement Project (FSRP). Similar to AMI and FSRP, we expect that using this integrated approach with CET will provide benefits and reduce the overall cost of system replacement, although it is too early in the process to quantify these savings precisely.

Q. Why do PGE's CIS and MDMS systems need to be replaced?

A. PGE's current CIS and MDMS systems have been a prudent investment for our customers and they have been used since 2002 and 2000, respectively, and will be over 15 years old by the time they can be replaced. While PGE is consistently improving service to customers with the tools it already has in place, PGE's current systems are nearing the end of their useful lives, have high maintenance costs, or are no longer supported by vendors, and are not technically and functionally suited for existing programs, such as billing for Net Metering, and emerging smart grid requirements, such as new pricing options. Many of these existing and emerging customer programs are currently now supported by manually intensive back-office work that has limited automation. We believe that further enhancements and changes to existing systems will be costly and slow, leading to even more manual processes as the systems become more aged and obsolete. While the need to replace the existing MDMS isn't as urgent as CIS, by implementing CIS and MDMS in parallel, PGE can integrate the systems once, thus avoiding subsequent expensive and duplicative work.

Q. Please describe the CET timeline and roadmap of initiatives.

A. PGE has developed a roadmap that specifies the sequence of the various initiatives beginning in 2012 and ending in 2018. The roadmap factors the interdependencies of each of the initiatives to maximize operational efficiencies and effectiveness. The CET roadmap is PGE Exhibit 903.

Q. What are the overall expected costs and benefits for the CET program?

A. PGE is at the very beginning of a multi-year effort. Consequently, PGE's estimates for the out years (i.e., the years 2015-2018) are preliminary. PGE will be better able to estimate costs in the out years as it selects replacement software and is able to estimate specific implementation costs. At this point, PGE expects that the full CET program, including the installation and configuration of the replacement systems and the operational improvement projects designed to optimize their value to customers, will cost approximately $22 million to $25 million incurred O&M and $70 million to $80 million incurred capital[6] to implement when fully complete in 2018. The largest components of the program in terms of scope and cost are the CIS and MDMS system replacements (PGE Exhibit 904). The annual ongoing net O&M reduction is estimated to be $4 million to $6 million[7,8] on an incurred basis once the program is complete in 2018.

Q. What are the 2014 activities within the CET program?

A. 2014 CET activities fall primarily into two categories:

- <u>Operational efficiency and effectiveness initiatives that will establish high-level requirements for the new systems and design business processes to take advantage of</u>

[6] Loaded and escalated range is estimated to be $32 million to $37 million O&M and $86 million to $98 million capital.
[7] The annual ongoing net O&M reduction on a loaded basis is estimated to be $7 million to $10 million.
[8] Net benefits include ongoing annual O&M reduction offset by increases in operating costs associated with new maintenance agreements, etc.

new systems. This work includes a set of customer strategy and governance initiatives designed to map out the long-term strategy for how PGE can capture and enhance insight into its customers' behaviors and preferences; interact with customers through the channels they choose (online, phone, community office, etc.), and deliver customer-valued products and services faster and more cost effectively. PGE will also improve its current workforce planning and scheduling tool to optimize the allocation of employees to workloads across Customer Service departments, and implement a tool for managing individual and team performance metrics. Finally, PGE will increase efficiency by automating manual work processes.

- Activities necessary to prepare for, select, and design new customer systems. Leveraging the outputs created by operational and effectiveness initiatives, PGE will develop high-level system requirements and select the software packages that best meet PGE's customer and regulatory requirements. PGE will also prepare for system replacement by completing specific technical activities that include reviewing customer data for completeness, accuracy, consistency, and integrity. This effort is a requirement for moving to a new CIS and MDMS and includes the purchase of a data quality tool.

A. Smart Grid

Q. What benefits does PGE see that can be derived from development of the smart grid and what have you achieved to date?

A. The advancement of a smart grid will augment the benefits that customers receive from the power system. It will enhance the customer experience, lower the long-term cost of utility operations, and enable the integration of larger amounts of renewables and distributed generation. For the utility, the smart grid has the potential to improve the reliability, safety, security and efficiency of the transmission and distribution network. These are both attractive and necessary goals.

In UM 1460, the Commission's stated goal is to "... benefit ratepayers of Oregon's investor-owned utilities by fostering utility investments in real-time sensing, communication, control, and other smart-grid measures that are cost-effective". PGE has embraced this goal.

Over the past decade, PGE has engaged in a number of activities that are now considered to be part of the Smart Grid, and we will continue to make advances that provide the most benefits for our customers. Recent projects are financially leveraged, having received significant funding from external sources (e.g. USDOE). The foundational work that PGE has completed positions PGE as a smart grid leader, both in Oregon and the nation. This work includes the installation of over 800,000 digital smart meters, nearly 90 MWs of Distributed Standby Generation (DSG) program, a public Electric Vehicle (EV) charging infrastructure, as well as the implementation of renewable energy programs and system reliability enhancements; all of which were met with strong customer satisfaction.

Q. What are PGE's plans for Smart Grid?

A. In 2012, the Commission ordered that PGE develop a Smart Grid Report by June 1, 2013. The report will highlight existing and planned PGE efforts and also discuss PGE views on near term smart grid activities and projects. As a general guideline in that order, the Commission further stated that "Utilities should be evaluating promising smart-grid technologies and applications on an ongoing basis..."

Q. What are PGE's plans for Smart Grid in the 2014 test year?

A. PGE expects to continue foundational efforts in 2014, such as completing our SCADA build-out, implementing our T&D Transformation Plan and operating our portion of the Northwest smart grid Demonstration (the Salem Smart Power Project). PGE will also continue to study and follow regional and national smart grid efforts to ensure PGE's efforts are aligned with best practices. In addition, we will expand research, analysis, and planning and platform development in several areas, including: distribution automation; distributed energy resources; IT; and customer-education as well as efforts in the area of demand response programming.

PGE's Smart Grid Roadmap sets the vision of what PGE believes is achievable during the planning period. It will be based on the maturity of smart grid technologies, the value they can deliver, and, most importantly, customer readiness for their implementation.

Q. Will this expanded work require additional FTEs?

A. Yes. The transition to a smarter grid will be a significant challenge. It involves far more than simply leveraging new technology. To date, our smart grid efforts have been funded primarily as replacement of obsolete systems, using existing capital budgets for reliability improvements governed by standard design practices, or through limited R&D funds. To derive a thoughtful, customer-supported business case for advanced smart grid applications and to facilitate smart grid planning and implementation, 5.0 additional FTEs are sought with the following justification:

- PGE needs to recruit qualified employees with skill sets related to smart grid planning and implementation that are currently not resident; analysis and research requires in-house engineers and analysts who have advanced skill sets in technologies and a comprehensive understanding of PGE data systems, including Advanced Metering

Infrastructure (AMI), Geo-Spatial Information System (GIS), Outage Management System (OMS), marketing and other mass data support.

Q. Can you briefly describe the activities that would be performed by these positions?

A. Yes. There are four positions in Customer Strategies & Business Development and one in Distribution that are discussed below:

Building on what we already have and know: The first FTE, in Customer Strategies and Business Development (CS&BD), will be a Smart Grid Data Analyst, responsible for sophisticated statistical analyses of voltage, energy and outage data from PGE's AMI and SCADA systems in order to identify where O&M savings can be achieved through creation of specific smart grid actions. This position will collect business requirements for advanced data analytics, and then work with IT as they develop software architecture to integrate smart grid data features.

Understanding and anticipating emerging standards: The second FTE in CS&BD will be a Customer Equipment & Standards Engineer. This expertise is needed to review and recommend equipment suitable for future programs and support analysis and integration of emerging standards for the programming found in smart appliances that are emerging in the marketplace. This position will work to create requirements for vendors and IT to minimize customer interface problems.

Developing systems to analyze data: The third FTE in CS&BD will be a Smart Grid Systems Architect. This position will work with program managers to define and manage system requirements for new smart grid engineering applications to support data analytics as well as management of demand response, distributed generation, and other smart grid concerns.

Developing cost-effective business cases: The fourth FTE in CS&BD will be a Smart Grid Project Manager tracking progress on all smart grid projects in the company and the costs associated with them. This position will provide the primary writing, collection and synthesis of the annual report due to the OPUC every June 1st. This position will provide project management support for all smart grid related R&D and act as liaison to external stakeholders regarding information about PGE programs and joint efforts.

Deploying Smart Grid technology cost-effectively: The fifth FTE, located in Transmission & Distribution, will be a Smart Grid Distribution Automation Engineer. This position will complete detailed assessments of emerging grid technologies and their benefits, such as increased reliability from self-configuring networks and capacity/energy savings from grid optimization. Activities for this position include an ongoing effort to research emerging best practices, performing complex engineering assessments, and potential extensive field trials designed to assess actual versus predicted benefits. As part of PGE's broader smart grid implementation efforts, this position will also look for benefits that can be achieved through cross-functional use of corporate assets, particularly important to create the highest value from the T&D enterprise applications being installed in 2012 through 2014.

B. Bank Card

Q. You stated that PGE has a proposal for a "no fee" bank card program. Please describe PGE's current bank card option for web and phone payments.

A. Since 1999, PGE customers have been able to make payments via the web or phone using debit or credit cards. This payment option is managed through a third-party vendor, Bill Matrix. Customers using the bank card option are required by the vendor to pay a user fee— currently $2.95—each time they make a transaction through the vendor's service.

Q. How many customers use the bank card payment option?

A. Today, approximately 2.5% percent of PGE's customers use this third-party payment option. In 2012, approximately 170,000 Bill Matrix transactions were made through the web and IVR. This translates to approximately $29 million in payments received by PGE and approximately $600,000 in fees paid by customers.

Q. Please describe PGE's proposal for bank cards.

A. PGE proposes to include in base rates the costs associated with residential customers' use of bank cards for payment, including both credit and debit cards. These costs include the fees charged by credit card companies, banks and third-party processors. The proposed program is limited to payment of residential customer bills to help manage the total cost of those fees. Non-residential customers will continue to have a bank card option available to them under the existing fee-based program.

Q. How does the proposed program benefit customers?

A. Customers have asked for a "no fee" bank card program for many years; in fact, it is the number one comment on customer feedback surveys, which often cite convenience as the primary benefit. Other merchants and service providers readily accept card payments without associated fees and PGE's customers expect the same from PGE. PGE's program will expand on the payment options already available to residential customers, making payment easier. Northwest Natural recently started a "no fee" program.

Q. How much will the proposal cost?

A. PGE expects the program cost to be $1.6 million in 2014, based on a 15% adoption rate. PGE's calculations are provided in PGE Exhibit 905.

Q. How did PGE derive the estimated 15% adoption rate for bank card payments?

A. PGE surveyed other utilities that had eliminated the user fee for bank card payments and found a range of adoption rates from 10% to about 13%. However, most utilities had enrollment restrictions, such as such as mandated paperless billing. Since PGE's program will not have similar restrictions, PGE expects a slightly higher adoption rate.

C. Summary

Q. You have stated that PGE's mission for Customer Service is to deliver value to its customers by providing excellent service at a reasonable price. Do you believe the initiatives planned within your Customer Service organizations are necessary to achieve this?

A. Yes. We believe that the initiatives PGE has completed, the projects currently underway and the comprehensive plans PGE has for the future demonstrate PGE's commitment to its customers and provide the best opportunity to operate our business effectively and efficiently while delivering the products and services that meet customer expectations.

IV. Qualifications

Q. Ms. Stathis, please describe your qualifications.

A. I serve as Vice President, Customer Service Operations, at Portland General Electric and have been in this role since June, 2011. In this position I am responsible for operational functions including smart metering, billing, credit and collections, community offices and the contact center. I began my career with PGE nineteen years ago as a financial analyst. Since then, I have served in a number of roles including assistant treasurer and manager of Corporate Finance, general manager of Power Supply Risk Management and general manager of Revenue Operations.

Q. Ms. Stathis, please state your educational background and experience.

A. I received a Bachelor of Science Degree in Political Science from Willamette University and a post-baccalaureate certificate in accounting from Portland State University. I previously qualified as a certified public accountant in the State of Oregon. I am on the boards of Marylhurst University, the Oregon Alliance of Independent Colleges and Universities, and the advisory board for the University of Idaho Utility Executive Course.

Q. Ms. Dillin, please describe your qualifications.

A. I serve as Vice President, Customer Strategies and Business Development at Portland General Electric (PGE) and have been in this role since June, 2011. In this position I am responsible for the Retail Customer Strategies for the company. This includes Customer Research and Analysis, Customer Program Development and Management, Retail Technical Strategies, Business Customer Group, Smart Grid and R&D. I began my career at PGE twenty-five years ago as a Public Information Specialist. Since then, I have served in a number of roles, including Director, Corporate Communications and Community Affairs, and President of the PGE Foundation. I served as Vice President, Public Policy from 2004 to 2009 until I was appointed to my current position.

Q. Ms. Dillin, please state your educational background and experience.

A. I received a Bachelor of Arts in Journalism and Spanish from the University of Oregon. I have taken post-graduate business courses at Marylhurst University, and am a graduate of the American Leadership Forum class of 2005. I am on the boards of The Earth Advantage Institute; The Center for Women, Politics and Policy; PGE Foundation; and the Westside Economic Alliance. I also serve on the business advisory council for the Portland State University School of Business.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
901	PGE Benchmarking and Survey Results Summary
902	Trends – Customer Preference Shifts
903C	Customer Engagement Transformation (CET) Roadmap
904C	CIS – MDMS System Replacements – Cost Estimates
905	Bank Card – Adoption Rate Calculations

2012 Customer Service Benchmarking

Summary of Results, prepared by PGE

Background

In 2012, PGE participated in a Customer Service benchmarking study conducted by PA Consulting Group. The study included 16 utilities from around the country and was based on 2011 data supplied by the utilities.

The Customer Service functions included in the benchmarking study were:

Contact Center	Field Service
Billing	Credit & Collection
Payment	Revenue Assurance
Meter Reading	Self Service

Report Summary & Discussion

The PA Consulting reports benchmark PGE against all other study participants and provide three summary-level quartile rankings including 1) service effectiveness (which PA Consulting refers to as "Service One"), 2) cost (total customer service expenses per customer), and 3) overall results.

PGE Customer Service scored in the first quartile (Draft Scorecard, page 19) of all study participants for "Service One" metrics, reflecting timely, accurate and effective service to customers primarily in the areas of meter reading, billing, and credit and collections.

PGE ranked in the third quartile for cost (Executive Summary, page 14) and overall (Draft Scorecard, page 10). Primary drivers for PGE's cost ranking as compared to other participants include: 1) inclusion of amortization expense for PGE's automated metering infrastructure (AMI) systems in meter reading costs (most companies in the study did not have fully deployed AMI and therefore did not have any amortization costs), 2) inclusion of the labor to staff PGE's seven community offices in payment processing costs (approximately half the companies in the study had community offices and all scored third and fourth quartile for the cost of payment processing), and 3) PGE's higher number of employees performing the work, largely driven by manual work due to functionally obsolete systems.

In addition to providing quartile rankings, the Executive Summary report (page 13) contains several suggestions for PGE improvements. Some suggestions had been implemented prior to the delivery of the report, and many were either underway or planned. Others will be evaluated further for validity.

Below is context for certain of the opportunities for improvement mentioned in the report:

- Contact Center
    - Improve selected service levels: Since 2011 (data supplied for study) PGE has made operational improvements with favorable impact to certain measures. For example, Service Level was improved from fourth quartile (per the report) to top of the second quartile range (using 2012 PGE data).
    - Improve data quality: During the analysis period the contact center phone system experienced an issue that caused some data to be unavailable. The issue has since been resolved.

- Payment
    - Outsource payments: PA Consulting recommends outsourcing payment functions when the utility has less than 1 million customers. PGE believes that after removing the cost of staffing community offices, which PA Consulting includes in the cost of payment processing, PGE's cash remittance function is competitive with outsource options.
    - Eliminate local offices: PGE does not consider its community offices to be simply a payment channel, and believes they offer additional value to customers and the community.

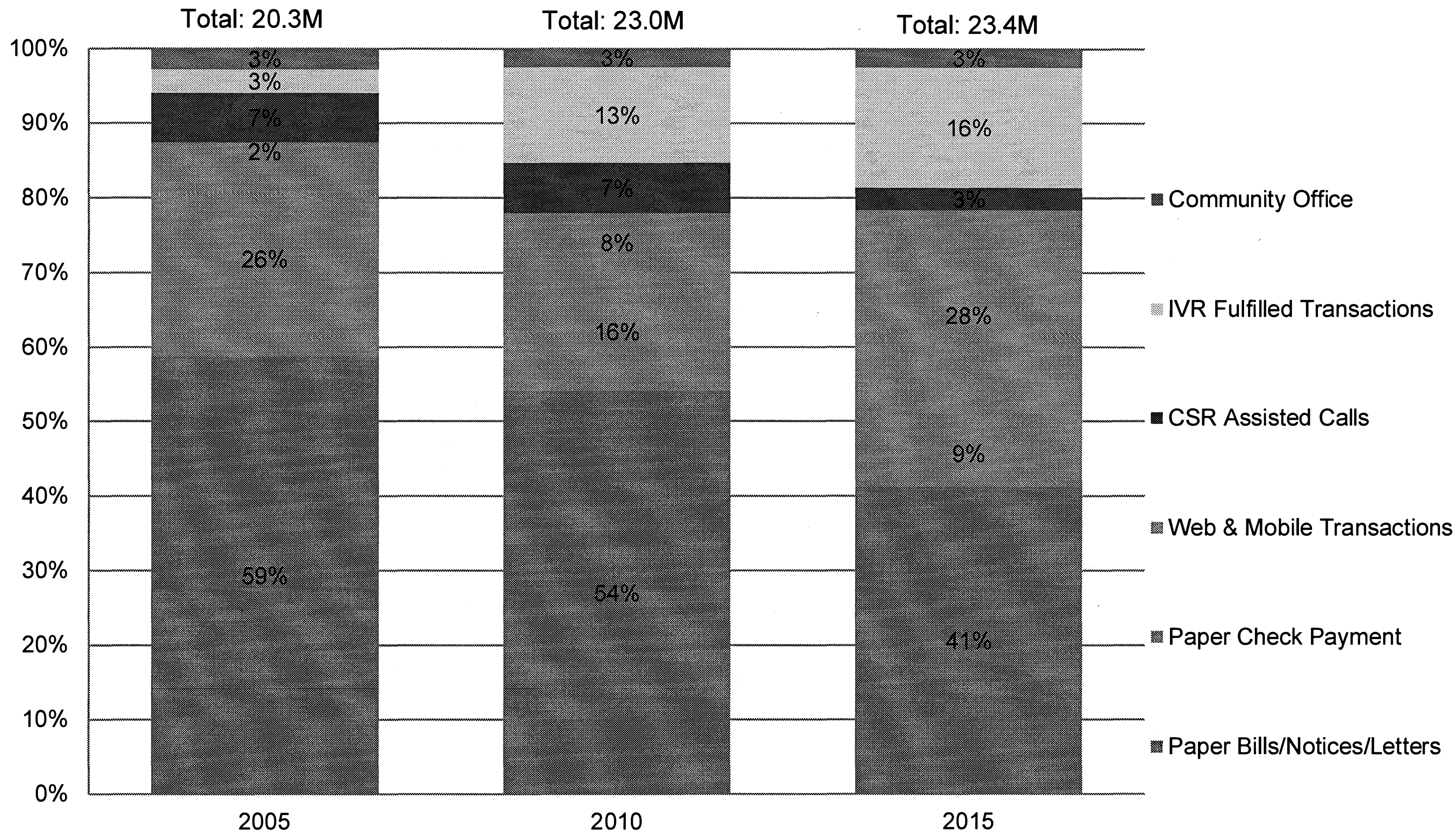
- Credit and Collections
    - Disconnect more customers, discontinue collection in the field, and make fewer payment arrangements: These recommendations will be evaluated to ensure multiple perspectives are considered to determine best approach to these business practices.

<u>Attachments</u>

PA Consulting Draft Scorecard, dated August 7, 2012 (see Confidential Work Papers)
PA Consulting Executive Summary, dated September 21, 2012 (see Confidential Work Papers)

Continuous Improvement Update:

How Customer Interaction with PGE Is Changing



2/9/2013

Note: 2005 and 2010 data based on actuals; 2015 projection based on customer trends and planned PGE projects

Exhibit 903C

Confidential

Exhibit 904C

Confidential

Customer Pymt Count	9,030,141

Overall Customer Adoption Breakdown						
Adoption Rate	Count	Tier 1	Tier 2	Tier 3	Tier 4	Total (Crosscheck)
Value		≤225000	375000	525000	>525000	
1%	90,301	90,301				90,301
2%	180,603	180,603				180,603
3%	270,904	225,000	45,904			270,904
4%	361,206	225,000	136,206			361,206
5%	451,507	225,000	150,000	76,507		451,507
6%	541,808	225,000	150,000	150,000	16,808	541,808
7%	632,110	225,000	150,000	150,000	107,110	632,110
8%	722,411	225,000	150,000	150,000	197,411	722,411
9%	812,713	225,000	150,000	150,000	287,713	812,713
10%	903,014	225,000	150,000	150,000	378,014	903,014
11%	993,316	225,000	150,000	150,000	468,316	993,316
12%	1,083,617	225,000	150,000	150,000	558,617	1,083,617
13%	1,173,918	225,000	150,000	150,000	648,918	1,173,918
14%	1,264,220	225,000	150,000	150,000	739,220	1,264,220
15%	1,354,521	225,000	150,000	150,000	829,521	1,354,521
16%	1,444,823	225,000	150,000	150,000	919,823	1,444,823
17%	1,535,124	225,000	150,000	150,000	1,010,124	1,535,124
18%	1,625,425	225,000	150,000	150,000	1,100,425	1,625,425
19%	1,715,727	225,000	150,000	150,000	1,190,727	1,715,727
20%	1,806,028	225,000	150,000	150,000	1,281,028	1,806,028
21%	1,896,330	225,000	150,000	150,000	1,371,330	1,896,330
22%	1,986,631	225,000	150,000	150,000	1,461,631	1,986,631
23%	2,076,932	225,000	150,000	150,000	1,551,932	2,076,932
24%	2,167,234	225,000	150,000	150,000	1,642,234	2,167,234
25%	2,257,535	225,000	150,000	150,000	1,732,535	2,257,535

VISA Breakdown (50%)							
Adoption Rate		Tier 1	Tier 2	Tier 3	Tier 4	Total (Crosscheck)	
Value		≤225,000	375,000	525,000	>525,000		
1%	45,151	45,151	-	-	-	45,151	OK
2%	90,301	90,301	-	-	-	90,301	OK
3%	135,452	135,452	-	-	-	135,452	OK
4%	180,603	180,603	-	-	-	180,603	OK
5%	225,754	225,000	754	-	-	225,754	OK
6%	270,904	225,000	45,904	-	-	270,904	OK
7%	316,055	225,000	91,055	-	-	316,055	OK
8%	361,206	225,000	136,206	-	-	361,206	OK
9%	406,356	225,000	150,000	31,356	-	406,356	OK
10%	451,507	225,000	150,000	76,507	-	451,507	OK
11%	496,658	225,000	150,000	121,658	-	496,658	OK
12%	541,808	225,000	150,000	150,000	16,808	541,808	OK
13%	586,959	225,000	150,000	150,000	61,959	586,959	OK
14%	632,110	225,000	150,000	150,000	107,110	632,110	OK
15%	677,261	225,000	150,000	150,000	152,261	677,261	OK
16%	722,411	225,000	150,000	150,000	197,411	722,411	OK
17%	767,562	225,000	150,000	150,000	242,562	767,562	OK
18%	812,713	225,000	150,000	150,000	287,713	812,713	OK
19%	857,863	225,000	150,000	150,000	332,863	857,863	OK
20%	903,014	225,000	150,000	150,000	378,014	903,014	OK
21%	948,165	225,000	150,000	150,000	423,165	948,165	OK
22%	993,316	225,000	150,000	150,000	468,316	993,316	OK
23%	1,038,466	225,000	150,000	150,000	513,466	1,038,466	OK
24%	1,083,617	225,000	150,000	150,000	558,617	1,083,617	OK
25%	1,128,768	225,000	150,000	150,000	603,768	1,128,768	OK

MasterCard Breakdown (25%)							
Adoption Rate		Tier 1	Tier 2	Tier 3	Tier 4	Total (Crosscheck)	
Value		≤225,000	375,000	525,000	>525,000		
1%	22,575	22,575	-	-	-	22,575	OK
2%	45,151	45,151	-	-	-	45,151	OK
3%	67,726	67,726	-	-	-	67,726	OK
4%	90,301	90,301	-	-	-	90,301	OK
5%	112,877	112,877	-	-	-	112,877	OK
6%	135,452	135,452	-	-	-	135,452	OK
7%	158,027	158,027	-	-	-	158,027	OK
8%	180,603	180,603	-	-	-	180,603	OK
9%	203,178	203,178	-	-	-	203,178	OK
10%	225,754	225,000	754	-	-	225,754	OK
11%	248,329	225,000	23,329	-	-	248,329	OK
12%	270,904	225,000	45,904	-	-	270,904	OK
13%	293,480	225,000	68,480	-	-	293,480	OK
14%	316,055	225,000	91,055	-	-	316,055	OK
15%	338,630	225,000	113,630	-	-	338,630	OK
16%	361,206	225,000	136,206	-	-	361,206	OK
17%	383,781	225,000	150,000	8,781	-	383,781	OK
18%	406,356	225,000	150,000	31,356	-	406,356	OK
19%	428,932	225,000	150,000	53,932	-	428,932	OK
20%	451,507	225,000	150,000	76,507	-	451,507	OK
21%	474,082	225,000	150,000	99,082	-	474,082	OK
22%	496,658	225,000	150,000	121,658	-	496,658	OK
23%	519,233	225,000	150,000	144,233	-	519,233	OK
24%	541,808	225,000	150,000	150,000	16,808	541,808	OK
25%	564,384	225,000	150,000	150,000	39,384	564,384	OK

Regulated Debit Breakdown (10%)							
Adoption Rate		Tier 1	Tier 2	Tier 3	Tier 4	Total (Crosscheck)	
Value		≤225,000	375,000	525,000	>525,000		
1%	13,545	13,545	-	-	-	13,545	OK
2%	27,090	27,090	-	-	-	27,090	OK
3%	40,636	40,636	-	-	-	40,636	OK
4%	54,181	54,181	-	-	-	54,181	OK
5%	67,726	67,726	-	-	-	67,726	OK
6%	81,271	81,271	-	-	-	81,271	OK
7%	94,816	94,816	-	-	-	94,816	OK
8%	108,362	108,362	-	-	-	108,362	OK
9%	121,907	121,907	-	-	-	121,907	OK
10%	135,452	135,452	-	-	-	135,452	OK
11%	148,997	148,997	-	-	-	148,997	OK
12%	162,543	162,543	-	-	-	162,543	OK
13%	176,088	176,088	-	-	-	176,088	OK
14%	189,633	189,633	-	-	-	189,633	OK
15%	203,178	203,178	-	-	-	203,178	OK
16%	216,723	216,723	-	-	-	216,723	OK
17%	230,269	225,000	5,269	-	-	230,269	OK
18%	243,814	225,000	18,814	-	-	243,814	OK
19%	257,359	225,000	32,359	-	-	257,359	OK
20%	270,904	225,000	45,904	-	-	270,904	OK
21%	284,449	225,000	59,449	-	-	284,449	OK
22%	297,995	225,000	72,995	-	-	297,995	OK
23%	311,540	225,000	86,540	-	-	311,540	OK
24%	325,085	225,000	100,085	-	-	325,085	OK
25%	338,630	225,000	113,630	-	-	338,630	OK

Un-Regulated Debit Card Breakdown (15%)							
Adoption Rate		Tier 1	Tier 2	Tier 3	Tier 4	Total (Crosscheck)	
Value		≤225,000	375,000	525,000	>525,000		
1%	9,030	9,030	-	-	-	9,030	OK
2%	18,060	18,060	-	-	-	18,060	OK
3%	27,090	27,090	-	-	-	27,090	OK
4%	36,121	36,121	-	-	-	36,121	OK
5%	45,151	45,151	-	-	-	45,151	OK
6%	54,181	54,181	-	-	-	54,181	OK
7%	63,211	63,211	-	-	-	63,211	OK
8%	72,241	72,241	-	-	-	72,241	OK
9%	81,271	81,271	-	-	-	81,271	OK
10%	90,301	90,301	-	-	-	90,301	OK
11%	99,332	99,332	-	-	-	99,332	OK
12%	108,362	108,362	-	-	-	108,362	OK
13%	117,392	117,392	-	-	-	117,392	OK
14%	126,422	126,422	-	-	-	126,422	OK
15%	135,452	135,452	-	-	-	135,452	OK
16%	144,482	144,482	-	-	-	144,482	OK
17%	153,512	153,512	-	-	-	153,512	OK
18%	162,543	162,543	-	-	-	162,543	OK
19%	171,573	171,573	-	-	-	171,573	OK
20%	180,603	180,603	-	-	-	180,603	OK
21%	189,633	189,633	-	-	-	189,633	OK
22%	198,663	198,663	-	-	-	198,663	OK
23%	207,693	207,693	-	-	-	207,693	OK
24%	216,723	216,723	-	-	-	216,723	OK
25%	225,754	225,000	754	-	-	225,754	OK

Change Card Adoption Mix using cells K6 - N6

CARD BREAKDOWN					
Adoption Rate	Visa	MC	Reg Debit	Non-Reg Debit	Total (Crosscheck)
Value	50%	25%	15%	10%	100%
1%	45,151	22,575	13,545	9,030	90,301
2%	90,301	45,151	27,090	18,060	180,603
3%	135,452	67,726	40,636	27,090	270,904
4%	180,603	90,301	54,181	36,121	361,206
5%	225,754	112,877	67,726	45,151	451,507
6%	270,904	135,452	81,271	54,181	541,808
7%	316,055	158,027	94,816	63,211	632,110
8%	361,206	180,603	108,362	72,241	722,411
9%	406,356	203,178	121,907	81,271	812,713
10%	451,507	225,754	135,452	90,301	903,014
11%	496,658	248,329	148,997	99,332	993,316
12%	541,808	270,904	162,543	108,362	1,083,617
13%	586,959	293,480	176,088	117,392	1,173,918
14%	632,110	316,055	189,633	126,422	1,264,220
15%	677,261	338,630	203,178	135,452	1,354,521
16%	722,411	361,206	216,723	144,482	1,444,823
17%	767,562	383,781	230,269	153,512	1,535,124
18%	812,713	406,356	243,814	162,543	1,625,425
19%	857,863	428,932	257,359	171,573	1,715,727
20%	903,014	451,507	270,904	180,603	1,806,028
21%	948,165	474,082	284,449	189,633	1,896,330
22%	993,316	496,658	297,995	198,663	1,986,631
23%	1,038,466	519,233	311,540	207,693	2,076,932
24%	1,083,617	541,808	325,085	216,723	2,167,234
25%	1,128,768	564,384	338,630	225,754	2,257,535

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 262

Corporate Support

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Maria Pope
Alex Tooman

February 15, 2013

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I. Introduction

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

A. My name is Maria Pope. I am the Senior Vice President, Finance, Chief Financial Officer, and Treasurer at PGE. My qualifications appear in PGE Exhibit 200.

My name is Alex Tooman. I am a Project Manager for Regulatory Affairs at PGE. My qualifications appear in PGE Exhibit 300.

Q. What is the purpose of your testimony?

A. We explain PGE's request for $156.8 million in administrative and general (A&G) costs in 2014 and compare it to 2011 actuals of $143.2 million. We also provide context to show how these expenditures support PGE's ability to meet our customers' need for safe, reliable electric power at a reasonable cost, with service standards and practices that conform to commonly-accepted norms in today's global business and technological environments.

Q. What functions are classified as A&G and what are the costs of those functions?

A. We classify as A&G those functions that support PGE's direct operations to deliver electric power to customers, such as human resources, accounting and finance, insurance, contract services and purchasing, corporate security, regulatory affairs, legal services, and information technology (IT). We also include other costs such as employee benefits and incentives, support services, and regulatory fees that fall within the FERC definition of A&G. PGE Exhibit 1001 provides a list of A&G functions plus a summary of costs and full time equivalent (FTE) employees for 2010 (actuals) through 2014 (test year forecast). Table 1 below summarizes the major A&G costs by functional area.

Table 1
A&G Costs by Major Functional Area ($ million)*

Major Functional Areas	2011 Actuals	2014 Forecast	Delta 2014-2011
Facilities/General Plant Maintenance	$4.9	$4.7	$(0.2)
Accounting/Finance/Tax	$10.2	$9.9	$(0.3)
HR/Employee Support	$5.6	$7.9	$2.3
Insurance, Injuries and Damages, etc.	$11.2	$12.9	$1.7
Legal	$8.8	$7.0	$(1.9)
Regulatory Affairs/Compliance	$2.4	$3.8	$1.4
Corporate Governance	$3.0	$2.6	$(0.4)
Business Support Services	$2.7	$3.0	$0.2
Environmental Programs	$1.2	$2.6	$1.3
Corporate R&D	$0.9	$2.0	$1.0
Contract Services/Purchasing	$1.0	$1.5	$0.5
Security and Business Continuity	$1.1	$1.5	$0.5
Corp Communications/Public Affairs	$1.7	$1.6	$(0.0)
Load Research	$0.2	$0.2	$(0.0)
Hydro Licensing	$0.2 0	$0.2	$(0.0)
Performance Management	$0.9	$1.5	$0.6
Governmental Affairs	$1.3	$1.2	$(0.1)
Total for Major Functional Areas	$57.4	$64.0	$6.6
IT: Direct and Allocated	$11.5	$12.9	$1.3
Labor Cost Adjustment	$0.0	$(3.4)	$(3.4)
Membership Costs	$2.5	$3.3	$0.7
Incentive Plans (net of capital allocs.)	$16.0	$8.5	$(7.4)
Severance Costs	$0.7	$0.0	$(0.7)
Regulatory Fees	$6.6	$7.3	$0.7
General Plant Maintenance	$1.6	$2.6	$1.0
Net PTO	$5.8	$4.9	$(0.8)
Benefits (net of capital allocs.)	$42.0	$60.4	$18.5
Corporate Allocations	$(3.9)	$(6.2)	$(2.3)
Revolver Fees, Margin Net Int., Broker Fees	$3.0	$2.5	$(0.5)
Total Other A&G Costs	$85.8	$92.9	$7.1
Total A&G	$143.2	$156.8	$13.6

* May not sum due to rounding.

Q. How would you characterize the forecasted increase in A&G costs from 2011 to 2014?

A. Most of the A&G cost increase from 2011 to 2014 can be attributed to two primary drivers: benefits and regulatory compliance[1]. Benefits, as discussed in PGE Exhibit 500, are largely driven by pension and health care costs. Regulatory compliance encompasses the costs

[1] Excluding the increase in benefits alone, PGE A&G costs decline by approximately $4.8 million from 2011 to 2014, which represents a 1.1% annual decline.

associated with meeting requirements from various federal agencies related to system reliability, environmental protection, hydro licensing, and critical infrastructure protection. While we can and do actively manage costs associated with these drivers, they are primarily external to PGE and reflect larger market conditions and/or regulatory requirements beyond our control.

Q. Does your forecast include any cost reductions to offset these increases?

A. Yes. PGE has implemented a number of measures to increase efficiency and reduce costs. The primary impact of these measures has been in the form of a reduction in the number of employees, which we measure in the form of full time equivalent employees or FTEs.

Q. How is your testimony organized?

A. In the next section, we describe the cost efficiencies implemented in A&G and their impacts. We then discuss the major cost drivers by A&G function. Next, we provide detail regarding increases in other A&G costs. We then conclude by summarizing our request in this filing.

II. Efficiency Measures

Q. What measures have you implemented to improve efficiency and reduce costs?

A. Within A&G, PGE has implemented multiple programs to improve efficiency and effectiveness while reducing costs, including the following:

- Finance and Supply Chain Replacement Project (FSRP);
- IT Vision Design;
- Lean Process Reviews; and
- Time Collection System (myTime)

A. Finance, Accounting & Procurement – FSRP

Q. Please describe the FSRP program.

A. FSRP involved the replacement of PGE's obsolete financial and supply chain system, Masterpiece, with a new enterprise system that meets current standards for functionality and supports our goal of operational excellence. The new system was necessary because Masterpiece was 26 years old and was no longer supported by the vendor. In addition to addressing obsolescence, the new system automated a number of manual processes and streamlined workflow. In conjunction with work process analysis efforts, Finance and Accounting (F&A) was able to realize efficiencies through a net reduction of 15.3 FTEs.

Q. How has procurement's process improved through FSRP?

A. In 2011, as part of FSRP, PGE began using the PeopleSoft program as its primary supply chain software. PeopleSoft provides tools that allow for more effective management of the procurement process. Following the recommendations from the Financial Systems benchmark consultant, Price Waterhouse Coopers (PwC), PGE adopted leading practices to improve supply chain performance.

Q. What leading practices did PGE adopt?

A. Leading practices include electronic workflow with single fiscal approval, electronic dispatch of purchase orders, purchase order releases on master agreements, centralized invoice receipting with a three-way match, and strategic sourcing. The three-way-match process involves aligning the purchase order with the invoice and the receipt of goods or services.

Q. How have these best practices changed the procurement process?

A. One example is that prior to installation of PeopleSoft, paper requisitions were passed through interoffice mail taking days or even weeks to be approved. In PeopleSoft, electronic requisitions are routed for approval electronically and with the ability to approve from mobile devices. Workflow screens allow requisitioners to track the approval process online. Once the supply chain organization has completed work on a purchase order, it is dispatched automatically from PeopleSoft using electronic data interchange (EDI), email, or auto fax. Prior to PeopleSoft, many of PGE's purchase orders were mailed paper copies.

Q. What is the primary benefit of PeopleSoft for Procurement?

A. The PeopleSoft program, in conjunction with Oracle Business Intelligence (OBI) software, allows PGE buyers to run reports across the company that help them to better understand what PGE purchases. This capability to perform "spend analysis" is being used to combine like purchases and leverage PGE's buying power by using strategic sourcing.

Q. Please describe the strategic sourcing process.

A. The strategic sourcing process consists of performing spend analyses, identifying the business requirements, understanding the marketplace, developing a category strategy, evaluating and selecting suppliers, negotiating agreements, developing scorecards to measure supplier performance, and then repeating the process to drive on-going improvement.

Q. How far has PGE's strategic sourcing process advanced?

A. PGE's supply chain practices are still evolving as the supply chain organization continues to adopt the strategic sourcing model. It will take several years to accumulate spending history and properly align spending categories so that effective spend analyses can be performed. Buyers, once responsible for business units, are now responsible for categories of spending. This means that, rather than being an expert on one area of PGE operations, the buyer is expected to be an expert on a family of spending categories, e.g., consulting services.

Q. What cost savings and avoidance has the supply chain organization been able to achieve?

A. In 2012, PGE negotiated over $7.6 million of O&M cost savings and $2.6 million of O&M avoided cost savings that span multiple years (i.e., $1.4 million in 2012, $1.2 million in 2013, $1.1 million in 2014, and the remaining $6.5 million after 2014). The amount of savings realized is highly dependent on the type of work being performed. Some types of work, like construction, have larger opportunities than A&G spending. PGE Exhibit 1006 provides Utility Purchasing Management Group's (UPMG) industry accepted definition of cost savings and avoidance used by Procurement.

Q. How has the accounts payable process improved?

A. Accounts payable (A/P) activity is now centralized, enabling increased visibility into outstanding payables, reduced risk, and streamlined work processes. Through Lean Process Review (discussed in Section C, below) and implementation along with the automation of the A/P process in PeopleSoft, the department has been able to streamline workflow and improve its A/P cycle time to the industry best standard of 4 days.[2]

Q. What other work processes have improved in F&A?

A. Other improvements include:

- 40% reduction in cash management processing time;
- Automation of workflow and approvals for journal entries, projects and expense reports;
- Automation of 80% of book-tax adjustments; and
- 50% reduction in the number of general ledger accounts.

Q. Going forward, how will PGE continue to leverage financial system technology?

A. The Financial Systems Effectiveness Committee (FSEC) was created with a goal to maximize the functionality and capabilities of the new financial system and to drive for on going improvement. In 2012, over 50 initiatives were completed with projected annual savings of over 4,800 labor hours. Going forward, FSEC will expand its reach to encompass not only financial system initiatives but also work process standardization and Lean process improvement efforts.

Q. Are there any other efficiency initiatives occurring in F&A?

A. Yes. F&A continues to improve cost efficiency through the following activities:

- 1% rebate on annual Purchase Card purchases - PGE receives annual rebates from Bank of America for using its corporate credit cards for business transactions. For the March 2011 – 2012 time period, PGE received a rebate totaling $113,000. In 2013 and 2014, PGE projects savings of $110,000 and $112,000, respectively.

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[2] Based upon Hackett's definition of A/P cycle time.

- PGE continues to advocate and increase its usage of the Automated Clearing House (ACH) form of payment instead of written checks. Recently, all Public Purpose Charges (PPC) have moved to ACH. An ACH payment, on average, costs PGE about $0.05, while the expense associated with processing a check, on average, costs PGE about $5.36.

B. IT – Vision Design

Q. Please describe IT Vision Design.

A. IT Vision Design is a set of initiatives to develop and implement a roadmap for the future of IT at PGE in order to better support service to customers and cost-efficient business operations. IT Vision Design will improve IT's cost effectiveness, capabilities, and efficiency (as discussed in PGE Exhibit 600).

Q. What savings will be attained through IT Vision Design?

A. There is an ever-increasing demand for technology in today's business environment as it brings potential to create business efficiencies – for example, the realized efficiencies described above in F&A through FSRP implementation, which flow through to customers as reduced costs. Through IT Vision Design initiatives, IT will continue supporting PGE's growing need for technical infrastructure and support while achieving a net reduction of 7.8 FTEs. PGE Exhibit 600, Section III, Part B, provides more information on IT Vision Design.

C. Human Resources – Lean Process Reviews and myTime

Q. Please describe Human Resources' (HR) three main areas of focus for efficiency improvements, based upon recent benchmarking efforts.

A. The three main areas of focus of HR's efficiency efforts are the following:

- Create efficiencies in HR while maintaining effectiveness;
- Automate time and attendance, and payroll functions; and
- Review and modify, as appropriate, compensation and benefit contracts and outsourcing costs.

Q. How did you create efficiencies in HR?

A. In response to benchmarking results for HR, which illustrated HR's effectiveness but found room for improvement in efficiency as compared to industry peers, a transformation effort was launched in 2010. As part of the effort to improve operational efficiency, HR conducted a comprehensive analysis of HR processes and enlisted the expertise of outside consultants, The Corragio Group, to teach and help implement "Lean" (The analysis identified processes with the greatest potential for improvement that could benefit from the Lean methodology.). The goals of this effort are: 1) become more efficient and maintain a high level of service; 2) learn a new tool set to help employees 'think' differently about what we do and how we do it; and, 3) train process lead employees to assist in the roll out of Lean across the HR organization – as well as support other PGE departments that want to learn about Lean.

Q. What is Lean?

A. Lean is a process improvement methodology that focuses on removing inefficiencies from processes (e.g., wait time, errors, extra processing), so productivity as measured in time, costs, or resources can be enhanced.

Q. How are efficiencies achieved?

A. Efficiencies are achieved through increasing automation throughout the HR organization, reducing administrative processes; eliminating redundant steps; and evaluating vacated positions to identify ways to streamline or consolidate work so positions may not need to be refilled or the remaining work can be reassigned.

Q. How many Lean processes has HR completed?

A. HR has completed 20 Lean processes and currently has more in progress. PGE Exhibit 1002 provides a list of completed and in-progress Lean processes.

Q. What is the forecasted reduction in HR FTEs?

A. By 2014, we forecast a net reduction of 9.3 FTEs in HR. Lean implementation and the use of technology contribute to HR's ability to reduce and redeploy FTEs by streamlining workflow and reducing resources needed to complete work processes.

Q. Are there any other efficiency initiatives occurring in HR?

A. Yes. HR is currently focusing on two other major initiatives: 1) the deployment of a web-based time collection system called myTime; and 2) mitigation efforts focused on lowering PGE's benefit costs, such as renegotiating vendor contracts; reducing 401(k) Plan administration costs; and redesigning medical plans to reduce rate increases as well as prepare for health-care reform. PGE Exhibit 500, Section IV, provides additional information on PGE's benefit mitigation efforts.

Q. Please describe myTime.

A. myTime is a web-based time collection system that will increase accuracy and reduce time and materials spent on time-keeping processes and payroll going forward. myTime will replace the currently obsolete and cumbersome, paper time collection system.

Q. What are the projected benefits of myTime?

A. There are many benefits to myTime's implementation, which include the following:

- A $1 million adjustment to reduce wages and salaries in both 2013 and 2014 realized through:
  - The automation of complex pay rules such as union travel pay and premium time.
  - A reduction in manual transaction workflow on a paper-based process, thus reducing potential human error and the costs of re-work as well.
- Management will have more information regarding overtime hours worked and can allocate the workforce more effectively.
- Reduction in paper usage by moving to a web based system.
- Better information regarding contingent worker status for improved tracking of training compliance with North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) requirements.
- With a flexible and centralized system, PGE will have the ability to better adapt to the evolving environment of payroll, including changes to overtime, union agreements, new jobs and local/state/federal regulation.

Q. What is the overall change in FTEs within A&G?

A. Overall, the 2014 forecast reflects a net 24.9 FTE decline within A&G compared to 2011 actuals.

Q. Have there been any FTE increases that offset the reductions?

A. Yes. PGE projects the need for an additional 9 FTEs to meet new North American Electric Reliability Corporation (NERC) regulatory requirements. We discuss this in Section III, Part E, below.

III. Primary A&G Cost Increases

A. Benefits

Q. By how much do you forecast benefit costs to increase from 2011 to 2014?

A. The increase in net benefit costs from 2011 to 2014 is approximately $18.5 million and includes such items as health and dental plans, 401(k) plan, pension costs, workers' compensation, and employee life and disability insurance.

Q. What accounts for this increase?

A. The primary drivers of this increase are pension and health-care costs, which reflect funding requirements, inflation, and other cost pressures. PGE Exhibit 500 explains in greater detail how the compensation and benefits-related costs are affected by these increases and how PGE must address them to remain competitive in a labor market for specialized and qualified applicants who can help deliver the high service-quality levels expected of us. Please note that the benefit amounts in Table 1 represent the "net" changes within A&G only, as compared to the gross costs applicable to corporate PGE. Net A&G refers to the amount remaining in A&G after labor loadings apply certain amounts of these costs to capital projects and "below-the-line" activities. PGE Exhibit 500 explains the gross corporate forecast for these costs.

Q. How does PGE mitigate cost increases for benefits?

A. PGE works to keep benefit costs down through leadership and programs that encourage a healthy workforce, modifying benefits plan structures to track market practice, and negotiating for favorable contract terms. Our goal is to maintain a fair and appropriate benefits package that will help us attract and retain a quality workforce, while still controlling costs. For 2014, these efforts produced savings of $2.7 million. PGE

Exhibit 201 provides a summary listing of our cost mitigation efforts and PGE Exhibit 500, Section IV, provides greater detail on the efforts and programs related to compensation and benefits.

B. Insurance

Q. What types of insurance coverage does PGE maintain?

A. PGE maintains a prudent portfolio of insurance coverage, which we list and describe in PGE Exhibits 1003C (confidential) and 1004. In general, the insurance coverage maintained by PGE falls into three broad categories: Property, Liability, and Miscellaneous. We discuss these below and also address retained losses.

Q. What is PGE's forecast of insurance premiums for 2014?

A. As shown in Table 2 below, insurance premium costs are expected to be approximately $10.8 million in 2014, increasing from $8.4 million in 2011. The primary drivers of the increases are property and liability coverage. The increase in property premiums is due to an increase in PGE's Total Insured Value (TIV) and increases in premium rates. The liability program is expected to see rate increases affecting PGE's general liability, workers compensation, and directors and officers (D&O) liability.

Table 2
Insurance Premiums ($ million)

Type of Policy	2011	2014	Annual Average % Increase
Property	$4.1	$5.8	12.0%
Liability	$4.2	$4.8	5.0%
Miscellaneous	$0.15	$0.16	2.0%
Total	**$8.4**	**$10.8**	**8.5%**

Q. What is PGE's forecast of expenditures for retained losses from 2011 to 2014?

A. As shown in Table 3, PGE's expenditures for retained losses increase $200,000 from 2011 to 2014. We discuss retained losses in more detail below.

Table 3
Retained Losses ($ million)

Type of Loss	2011	2014	Annual Average % Increase
Workers' Compensation	$1.8	$1.9	1.8%
Auto & General Liability	$2.0	$2.1	1.6%
Total	**$3.8**	**$4.0**	**1.7%**

1. PGE's Insurance Policies

Q. How does PGE determine the appropriate amount of coverage limits?

A. In general, PGE purchases insurance to provide adequate financial protection from loss exposures that otherwise could result in an adverse material effect on PGE's financial stability and potentially negative impact on customers as well as the company. For certain lines of coverage, limit requirements are determined by regulatory bodies. PGE also consults with insurance brokers and other subject-matter experts concerning appropriate limits. Benchmarking studies and utility peer group comparisons are reviewed to ensure that PGE's practices for purchasing insurance are consistent with utility industry practice.

Q. How does PGE structure its coverage limits for the various types of insurance purchased?

A. Within the utility industry, the ability to sufficiently insure a loss exposure often requires capacity that is beyond the underwriting ability of a single insurer. To acquire adequate coverage limits and diversify exposure (so as to not excessively rely on any one carrier), an insurance structure is assembled whereby the primary insurer provides specific coverage terms and capacity limits; however, less than the total needed. Additional insurers provide supplemental capacity limits that are in "excess" of the primary layer while still following the form (basic terms and conditions) of the primary layer. In this context the term "excess" is a misnomer. It is not excess as normally defined but rather it denotes that the layer is supplemental to and attaches to the underlying layer to form a single cohesive insurance program. In structuring coverage this way, PGE is able to secure the adequate level of insurance capacity needed to protect against the adverse effects of severe losses with competitive pricing, as well as to diversify exposure to any one carrier.

Q. How does PGE forecast its insurance premium costs?

A. PGE bases its estimates on the most recent data for its insurance program, adjusted to account for:

- Amount and type of property or potential losses;
- Trends in insurance pricing and capacity provided by insurers, insurance brokers, consultants, and industry analysts;
- Changes expected in its various insurance programs in the coming years, such as increases or decreases in limits purchased, or property being added or retired, inflationary indexing of existing property base; and
- PGE-specific considerations, such as the frequency and severity of claims, which might have an impact on future premium expenses.

2. Current Trends

Q. What are the current trends in the insurance industry?

A. In 2012, overall rates began to show signs of hardening largely due to a low interest rate environment that has made it difficult for insurers to produce investment income with their collected premiums. However, there are other trends related to specific lines of insurance coverage, such as property insurance, general liability, and D&O liability.

Q. Please discuss the trends in the area of property insurance.

A. The leading driver of change in the global property insurance markets in 2012 was attributable to natural catastrophe losses around the world and PGE expects this pattern to continue in to 2013 as insurers try to rebuild their surplus.[3] In 2012, the global property market saw most insurers seeking moderate rate increases in the 3% to 9% range for those accounts in non-catastrophe exposed areas (e.g., flood, earthquake, named windstorm, etc.). Although PGE is exposed to flood and earthquake perils, the fact that it's not exposed to named windstorms greatly reduces its underwriting risk profile.

Q. What are the trends for general liability insurance?

A. Rate increases experienced in 2012 within the utility sector are expected to continue into 2013. These increases have been driven by large industry loss events such as the San Bruno (PG&E) gas pipeline explosion, California and Colorado wildfires, and the Tennessee Valley Authority ash-pond breach. Utilities can expect increased underwriting scrutiny and those with similar loss-exposure characteristics and/or those with other adverse loss experience should expect rate increases moving into 2013. Workers' Compensation coverage is expected to increase in 2013 due to a deteriorating Workers' Compensation insurance market driven by medical costs increasing faster than the rate of inflation.

[3] In 2011, natural catastrophic events included the earthquakes in Japan and New Zealand, flooding in Thailand and Australia and record-breaking tornadoes in the U.S. In October 2012, Hurricane Sandy struck the eastern U.S. wreaking havoc in multiple states. As of November 2012, storm damage from Hurricane Sandy is projected to reach $50 billion, which could be one of the costliest natural disasters in U.S. history.

Q. What are the trends for D&O liability insurance?

A. Although D&O rates have remained stable in 2012, there are indications of a modest hardening of prices moving into 2013. Over the past 12 months there have been at least 14 securities class action filings against publicly traded utilities, of which ten were "merger objection" filings.

Q. Are there other specific trends related to insurance coverage?

A. Yes. An emerging risk relates to data breaches that have continued to increase across the U.S. in the form of cyber-attacks and privacy breaches. In 2009, PGE added Network Security and Privacy Liability coverage to its insurance portfolio as a means to help mitigate the financial consequence of a cyber-attack or data breach.

3. Property Insurance

Q. You noted above that there was a general trend of insurance rates increasing approximately 3-9%. Does this trend explain the increase in PGE's property insurance premiums?

A. Yes, but only partially. As seen in Table 4 below, PGE's overall property insurance[4] premiums are forecasted to increase by approximately $1.7 million from 2011 to 2014. The increase in rates only accounts for part of the overall property insurance premium increase. The increase in our total insured values (TIV, i.e., plant additions and asset valuation) of the insured asset base also drives premium increases.

[4] Property insurance is comprised of All-Risk (Operational Risk and Builders Risk); Renewables (Operational Risk and Builders Risk) and Crime.

Table 4
Property Insurance Premium Increase
($ million)

	2011	2014	Annual Average % Increase
All-Risk*	3.0	4.4	13.6%
Renewables*	1.1	1.4	7.5%
Crime	0.03	0.03	0%
TOTAL	**$4.1**	**$5.8**	**12.0%**

* Includes Operational Risk and Builder's Risk

As seen in Table 4 above, the All-Risk total premiums increase $1.4 million from 2011 to 2014. This is due to rate increases of 18.7% and TIV increases of approximately 24.8% from 2011 to 2014. The renewables total premiums increase of $263,000 is due to an increase in rates of 10.5% and TIV of 19.2% from 2011 to 2014.

4. General Liability

Q. Please describe the premium increases in PGE's liability coverage.

A. General liability insurance covers PGE's liability from claims resulting from bodily injury or property damage arising out of PGE's operations, including the use of company vehicles. Given PGE's contact with its customers' premises and the dangerous nature of its operations, this insurance is of paramount importance. Premiums in PGE's general liability program are expected to increase overall by 4.7% from 2011 levels, driven primarily by the increase in general liability coverage (summarized in Table 5, below). As we note above, this increase in general liability coverage is due to recent industry losses that are now manifesting themselves in increased premiums as insurers seek to recover their losses by increasing their rates on existing accounts. Along with industry losses, PGE has had several claims creating upward rate pressure.

Table 5
General Liability Premium Increase
($ million)

Coverage	2011	2014	Annual Average % Increase
D&O	$1.41	$1.48	1.6%
Fiduciary	$0.14	$0.12	-3.7%
General Liability	$2.05	$2.53	7.3%
Miscellaneous *	$0.65	$0.74	4.2%
Total	**$4.25**	**$4.87**	**4.7%**

* Miscellaneous includes Workers' Comp, Cyber, and Nuclear

Q. Is D&O insurance coverage important?

A. Yes. D&O liability insurance shields PGE's directors and officers against normal, but sometimes significant, risks associated with managing the business. D&O insurance protects shareholders and customers from the consequences of financial distress and potential claims. Maintaining D&O insurance is necessary to attract and retain qualified and competent directors and officers. The limits purchased are consistent with the standard practice of the utility industry.

5. Retained Losses

Q. What method does PGE use to forecast workers' compensation, auto liability, and general liability losses?

A. PGE engages the services of an independent actuarial firm to provide loss projections related to auto and general liability losses. There is an inherent uncertainty associated with predicting loss events both in terms of frequency of occurrence and severity of loss. The actuarial firm assembles and analyzes data (over the past 10 to 20 years) to estimate the probability and likely cost of the occurrence of auto liability and general liability loss events.

Workers' compensation liability loss projections are based upon analysis of past claims and current available information. The following reasons explain the 1.8% increase in workers compensation projected loss:

- On a macro level, medical costs continue to increase faster than the rate of inflation;
- PGE specifically has an aging workforce, an increased rate of second surgeries and continuing claims expected to carry into the test year.

It is important to note that the annual budgeted claim expenditures for workers' compensation losses do not include the costs related to time loss or supplemental work loss payments (benefits for wages lost due to work related injuries). Such costs are already budgeted for within the wages and salaries (W&S). Time loss and supplemental work loss payments are equal to or less than the regular W&S received by the injured employee who cannot return to work.

Q. Why does PGE purchase workers' compensation insurance?

A. The State of Oregon requires PGE to maintain coverage in excess of its self-insured deductible to protect itself from catastrophic losses to employees arising out of and in the course of employment.

Q. What is the forecasted increase in annual claim expenditures for retained losses in workers' compensation and auto and general liability?

A. As shown in Table 3 above, annual claim expenditures for retained losses are forecasted to increase by approximately 1.7% between 2011 and 2014.

C. Research and Development

Q. What are PGE's forecasted 2014 costs for PGE's corporate research and development (R&D) activities?

A. For 2014, we forecast approximately $2.0 million in R&D expenses, of which $1.7 million is for specific R&D projects and the remainder is for administrative costs. This reflects an increase of approximately $1.0 million over 2011 actuals and represents numerous selected projects that are necessary to address the significant changes and new technologies facing PGE and the industry. These projects primarily relate to renewable energy, energy efficiency, electric vehicle transportation infrastructure, and smart grid applications, of which a few are listed below. It is important to note that these projects directly contribute to PGE's ability to evaluate and deploy technologies and resources that will benefit our customers for decades to come; helping to shape Oregon's energy future to conform to customer priorities for an ever more reliable and sustainable electric power system. We provide a complete listing with descriptions and benefits in PGE Exhibit 1005.

• Arundo Agronomy, other Regional Biomass Studies	$215,000
• Torrefaction Pilot Tests for Biomass	$188,000
• Smart Power Synchrophasor Reliability & Fast Command System	$91,280
• Second Life Application – EV Batteries	$53,692
• Vehicle to Home Concept (V2H)	$67,115
• Load Control EV Charging Station Demonstration	$34,900
• EcoDistrict Project, District Energy Development	$40,270
• Ductless Heat Pump Heat Recovery Whole House Ventilation	$13,423
• Modeling Wind Turbine Wake Effects using the PSU Wind Tunnel	$16,110

PGE will research areas in renewable power, smart grid, electric transportation and energy efficiency. The bulk of the renewable power research focuses on biomass power development in support of the potential transition from coal to a renewable biomass solid fuel for the Boardman Power plant. Aspects of wind, solar and wave technologies are also supported.

Q. What are you plans for smart grid projects?

A. PGE has several projects proposed in the smart grid area. These explore improving grid response to the increase in distributed sources of renewable power that are also variable and cannot be predicted with precision, let alone dispatched to meet demand. Addressing this form of power effectively and safely will be critical in support of the expected high level of adoption of these resources in the foreseeable future. We also focus on software development for controlling, sensing and monitoring the grid in much greater detail and frequency as grid operations evolve in the future. This need is fundamental because that which makes the smart grid "smart" is the software that must be created in order to utilize, synthesize, interpret, and react to the massive amounts of data that are becoming available from PGE's smart electric meters with two-way communications capability. This foreseeable evolution of the grid is being investigated through a Commission docket (UM 1460).

Utilities are required to report their intentions and interests in smart grid development. PGE will address these projects further in its Smart Grid Report due June 2013, which will describe how these efforts meet the Commission's guidelines as specified in Order No. 12-158.

Q. Please summarize your other R&D efforts.

A. In the development of electric transportation, it is very possible that internal combustion technology will eventually be replaced with electric drive systems in vehicles. In anticipation of that, PGE will focus R&D on promising infrastructure and systems that are becoming available to facilitate this technology.

The last area of projects involves focusing on technologies that have district-level application and/or can explore opportunities to educate electricity users so as to support constructive behavior that is conducive to efficient use of electrical energy.

Q. How will the 2014 R&D projects benefit customers?

A. First, many of the projects are leveraged financially by working with other utilities as well as universities to sponsor shared R&D. This means that PGE contributes a fraction of the overall research costs, but will receive 100% of the benefits much earlier than we otherwise would, if we did not contribute. PGE will work with several universities on shared projects that support unique, regional renewable power research such as wave, wind, solar, biomass, and CO_2 capture and sequestration. Finally, each project will provide specific benefits.

For example, PGE is researching the growing, charring, and combusting biomass as a substitute for coal at the Boardman Plant. Giant cane (*Arundo donax*) and other potential biomass stocks are renewable fuels, which if proven cost-effective, could be used to allow for the continuation of Boardman as a base-load power resource. This would significantly help PGE meet Oregon's renewable energy standard (RES), while reducing PGE's overall carbon footprint. PGE is also implementing projects in the Smart Grid area. The proposed research will build on PGE's Salem Smart Power Center where PGE has installed 5 MW of batteries that can store 1.25 MWh of energy and is sufficient to support the loss of a feeder line until a PGE distributed standby generator deploys.

Q. How have PGE's customers benefited from R&D in the past?

A. A recent example of how PGE customers benefited from R&D projects relates to wind research. In 2011 and 2012, PGE participated in a research project with Oregon State University that involved reviewing selected wind turbine performance at PGE's Biglow Canyon Wind Farm, which was constructed and brought onto the grid in three separate phases. The analysis focused on three questions:

- Are the Phase 2 Siemens 2.3 MW wind turbine yaw errors contributing to reduced performance?
- How did the Phase 3 Siemens 2.3 MW wind turbines performance compare to the Siemens 2.3 MW wind turbines in Phase 2?
- How were the Vestas 1.65 MW wind turbines in Phase I performing in relation to the supplier's power curves?

Q. What were the results of the research?

A. Results indicated that the yaw control system for the Phase 2 wind turbines appear to correctly align the rotor for the prevailing wind direction. This research also determined that the wind speed sensor for Turbine 334 was reading low and should be replaced. Phase 3 wind turbines – which are downwind on the project site - on average, produce less energy than Phase 2 turbines due to lateral turbulence levels. The most severe energy production loses occur in the summer months, at night, when the higher air density allows wake effects to extend deeper into the downwind array. Over time this will likely contribute to increased wear on the Phase 3 wind turbine yaw drive systems. This investigation recommended that the yaw controls be adapted for the higher lateral turbulence levels by having a slower response resulting in less yaw drive wear. The analysis also determined that the lower observed output for Turbines 7-12 can be attributed to upwind terrain differences especially at night when air flow becomes more stable and uniform. To date, this optimization investigation identified some wind turbine controls issues that needed to be corrected to reduce incremental O&M expenses, improve renewable energy production, and maximize recovery of Production Tax Credits on behalf of PGE's customers.

Q. Are there additional benefits to participating in the proposed research projects?

A. Yes. As noted in PGE's 2009 Integrated Resource Plan (IRP) and its most recent update (November 21, 2012), PGE must continue to add renewable resources to its system. By increasing funds to R&D programs that support increasing renewable power implementation, we will be proactive, rather than reactive, to evolving technologies and regulation (e.g., using charred-biomass renewable fuel and distributed solar generation). By supporting demonstration projects and activities with other research groups (e.g., EPRI, national laboratories, and universities), PGE will avoid missing opportunities to participate and direct how resources are developed for maximum customer benefit.

PGE must also continue involvement with, and provide support for, projects of increasing importance such as demand response, smart grid applications and carbon offsets/reductions. PGE must keep abreast of issues that remain under continued public scrutiny and may significantly benefit customers. PGE will use R&D funds to improve operation and maintenance of its generation and distribution systems and participate in opportunities to review and apply proposed system improvements through demonstration projects. PGE's participation in demonstration projects, trade programs, and specific-issue research has proven valuable to PGE's customers over the long run.

D. Environmental Services

Q. By how much do you expect environmental service costs to increase from 2011 to 2014?

A. We forecast that Environmental Service (ES) costs, as charged to A&G, will increase from approximately $1.2 million in 2011 to $2.6 million in 2014. This increase is primarily due to expanding regulatory reporting and compliance requirements (at federal, regional, state, and local levels) related to environmental issues. Ultimately, PGE has been and continues to be in compliance with environmental regulations, but as those regulations become more stringent, then our costs will increase, similar to compliance with expanding regulatory requirements related to other parts of PGE's business.

Q. Does this comprise all of the environmental costs charged to PGE?

A. No. The ES activities associated with investigation and reporting are incurred in A&G and the projects related to generation resources (e.g., fish-passage and habitat restoration, Clean Air Act and Clean Water Act compliance, plus waste handling and disposal) are incurred as part of Production O&M, which has the majority of ES costs. PGE Exhibit 700 provides detail on environmental compliance requirements, projects, and expenditures for our plants and facilities.

Q. Why specifically have these costs increased?

A. Environmental expenditures are increasing due to new requirements or modifications to existing regulations such as site certificates and permit and license requirements issued by the Oregon Energy Facility Siting Council (EFSC), Oregon Department of Environmental Quality (ODEQ), and Federal Energy Regulatory Commission (FERC) plus other regulations enacted by the EPA and other state and federal agencies. Additional compliance requirements and investigations relate, but are not limited, to increased license and reporting requirements involving some of the following PGE locations: 1) Oak Grove, North Fork, Faraday, River Mill, and the Sullivan Plant for fisheries, wildlife, and water quality license requirements; 2) Beaver/Port Westward Generating Sites for air quality and waste management/disposal; and 3) Pelton Round Butte for the Fish Health Management Program, which involves studying fish populations and potential changes in the distribution of fish disease agents associated with the new fish facilities at the site. Specific examples of requirements (that did not exist in 2011) involve:

- Climate Change – EPA, Oregon DEQ, and California Air Resources Board require PGE to report certain details regarding emissions of greenhouse gas related to our operations. Each program involves specific but differing monitoring and reporting methodologies that require PGE to develop programs for each. These programs are expected to increase in complexity as new phases are added. For example, sulfur hexafluoride (SF6) tracking and reporting for our transmission and distribution system was required in 2012 by EPA, and the California Air Resources Board has implemented a cap and trade program with which PGE will need to comply in 2013 and beyond.
- Portland Harbor Superfund – An ongoing effort to characterize, assign responsibility, and drive cleanup of the Portland Harbor from river miles 1.2 to 11.8. PGE is one of over 100 potentially responsible parties (PRPs). The next few years will be labor intensive to supply both the EPA and Allocation team with information required for evaluating and understanding relative responsibility in the harbor. Consequently,

PGE must develop its defense strategies and reviews of available public documents regarding PGE and its chief adversaries in the process. PGE will be heavily involved in reviewing, commenting, and developing a defense based on party site summaries developed by the allocation team, and developing advocacy materials.

PGE has identified all of its applicable historical domestic and London insurers that are still solvent, and has put them on notice of the environmental claim from the EPA. We have entered into defense cost sharing agreements with insurers that collectively provide for the reimbursement of approximately 45% of undisputed defense and investigation costs related to Portland Harbor. PGE continues to pursue recovery efforts from additional insurers. Consequently, the Portland Harbor costs are net of insurance proceeds that include an approximately $1.0 million credit to costs in the 2014 forecast.

- Downtown Reach – A subset of Portland Harbor. This is the river reach from river mile 11.8 to 16.0, which is under DEQ jurisdiction. PGE is under an Administrative Order of Consent by the DEQ to complete a Remedial Investigation (RI) and Feasibility Study (FS) for storm water discharge areas partially originating from PGE's Hawthorne Shop and previously owned Station L (currently OMSI). PGE has completed the RI and started the FS stage of review and reporting in 2012. Work will continue through 2014 with remedial design and permitting for the Downtown Reach.

E. Regulatory Compliance

Q. In Section II, you stated that PGE projects the need for a 9 FTE increase to meet NERC requirements. What are those requirements?

A. The NERC has developed updated standards for Critical Infrastructure Protection (CIP Version 5). These standards will provide a cyber-security framework for the identification and protection of the Cyber Systems that support reliable operation of the Bulk Electric System.

Q. Are these primarily A&G costs?

A. Most are IT costs and can be explained as follows. The incremental costs and FTEs associated with CIP Version 5 have been forecasted in the A&G department that is responsible for meeting federal compliance requirements. In Table 1, this appears in the line titled "Regulatory Affairs/Compliance" and accounts for most of the cost and FTE increases in that line. The majority of costs associated with CIP Version 5 activity, however, are IT costs that are allocated to PGE's operating areas (see PGE Exhibit 600, Section III, Part A for a description of IT allocations). Because they are primarily forecasted as IT costs, CIP Version 5 is discussed in greater detail in PGE Exhibit 600, Section III, Part B.

IV. Other A&G

A. Memberships

Q. Please explain the increase in the membership costs from 2011 to 2014?

A. PGE's membership costs are forecasted to increase from approximately $2.5 million (2011 actuals) to $3.4 million in 2014. Membership costs for PGE's mandatory participation in WECC account for most of this increase.

Q. Please explain the increase in WECC membership cost from 2011 to 2014.

A. WECC membership costs are projected to increase from approximately $1.0 million in 2011 to approximately $1.8 million in 2014. This increase is the result of additional compliance and regulatory oversight costs, which include the following items:

- A major outage in the southern California and Arizona in 2011 resulted in WECC adding significant numbers of personnel to enhance its reliability coordination role.
- WECC is currently expected to bifurcate into two organizations, with additional increases in cost. WECC's underlying philosophy is that those functions that are clearly covered by the delegation agreement are placed in the Regional Entity (RE) and those functions that are primarily offered as member services are placed in the Non-Regional Entity (Non-RE). The RE will encompass: 1) compliance monitoring and enforcement, and 2) reliability assessments and performance analysis. The Non-RE will encompass: 1) a reliability coordinator, and 2) operations and planning. Both entities will have separate general counsels and corporate services.

Q. Have there been any other significant increases in membership costs?

A. Yes. PGE's membership in the Northern Tier Transmission Group will increase by approximately $150,000 from 2011 to 2014.

B. Employee Support

Q. Why do the costs for HR/Employee Support increase from 2011 to 2014?

A. The majority of this increase, or approximately $1.2 million, relates to the Employee Support labor loading, which moves costs from A&G to capital and "below-the-line" activities according to PGE's loading and allocation policies, which are submitted annually to the OPUC Staff as an attachment to our Affiliated Interest Report. From 2011 to 2014, the employee support loading rate decreases so there are fewer costs loaded to capital, etc. In other words, the total employee support costs are not affected by this change but the amount that is removed from A&G declines by approximately $1.2 million so that net A&G appears to increase by this amount. The net change in costs for PGE as a whole, however, is zero.

V. Conclusion

Q. Please summarize your request for A&G in this filing.

A. We request that the Commission approve PGE's forecast of $156.8 million in A&G costs in the 2014 test year. This represents a $13.6 million increase since 2011 and is primarily driven by increases in employee benefits (i.e., health care and pension costs) and regulatory compliance (i.e., CIP Version 5, environmental mitigation, and WECC membership). Offsetting the increase, PGE has implemented programs in Finance and Accounting, Human Resources, Procurement, Accounts Payable, and Information Technology to reduce the 2014 forecast and to enhance our efficiency and effectiveness on an on-going basis.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
1001	Summary of A&G Costs and FTEs
1002	Summary of HR Lean Processing
1003C	Summary of Insurance Policies/Premiums
1004	Description of Insurance Coverage
1005	2014 R&D Project Detail
1006	UPMG's Definition of Cost Savings and Avoidance

A&G Summary

	Costs ($ millions)							FTEs						
	2010	2011	2012	2013	2014	2011 to 2014		2010	2011	2012	2013	2014	2011 to 2014	
Category	Actuals	Actuals	(9-3)	Budget	Budget	$ Delta	Annual %	Actuals	Actuals	(9)	Budget	Budget	$ Delta	Annual %
Major Functional Areas														
Facilities and General Plant Maintenance	4.7	4.9	4.6	4.3	4.7	(0.2)	-1.4%	12.2	11.7	13.0	12.4	12.4	0.7	2.0%
Accounting/Finance/Tax	8.5	10.2	9.1	9.0	9.9	(0.3)	-1.1%	85.2	84.7	73.5	71.0	69.4	(15.3)	-6.4%
HR/Employee Support (net of capital allocs.)	4.7	5.6	7.1	7.3	7.9	2.3	12.2%	112.7	115.7	104.2	106.3	106.3	(9.3)	-2.8%
Insurance / I&D	12.3	11.2	11.5	11.4	12.9	1.7	4.7%	6.5	6.6	6.7	6.9	7.0	0.4	1.7%
Legal	6.6	8.8	6.3	6.8	7.0	(1.9)	-7.6%	28.4	27.8	28.1	27.9	27.9	0.1	0.1%
Regulatory Affairs	2.4	2.4	2.4	2.8	3.8	1.4	16.3%	28.4	29.4	31.7	33.8	42.8	13.3	13.2%
Corporate Governance	3.2	3.0	3.0	2.9	2.6	(0.4)	-4.9%	13.9	13.8	14.2	14.1	14.1	0.2	0.5%
Business Support Services	2.7	2.7	2.7	2.7	3.0	0.2	2.7%	8.0	8.0	7.0	8.0	8.0	(0.0)	0.0%
Environmental Services	1.1	1.2	2.5	2.4	2.6	1.3	27.6%	-	-	-	-	-	-	
Corporate R&D	0.2	0.9	0.7	0.9	2.0	1.0	28.4%	0.6	1.0	1.0	1.0	1.0	-	0.0%
Contract Services/Purchasing	1.0	1.0	1.1	1.5	1.5	0.5	15.5%	22.7	24.4	22.0	22.0	22.0	(2.4)	-3.4%
Security and Business Continuity	1.2	1.1	1.3	1.5	1.5	0.5	12.7%	9.3	8.7	8.8	9.0	9.0	0.3	1.2%
Corp Communications/Public Affairs	1.9	1.7	1.9	1.6	1.6	(0.0)	-0.4%	22.1	21.8	25.8	22.5	22.5	0.7	1.1%
Load Research	0.2	0.2	0.3	0.2	0.2	(0.0)	-1.5%	-	-	-	-	-	-	
Hydro Licensing and Support	0.3	0.2	0.2	0.2	0.2	(0.0)	-6.2%	-	-	-	-	-	-	
Performance Management	0.9	0.9	1.1	1.4	1.5	0.6	19.5%	12.4	11.9	14.3	16.5	16.5	4.6	11.7%
Governmental Affairs	1.2	1.3	1.1	1.2	1.2	(0.1)	-2.6%	12.2	13.2	12.7	13.3	13.3	0.1	0.3%
Subtotal	53.1	57.4	57.0	58.3	64.0	6.6	3.7%	374.5	378.7	362.9	364.8	372.2	(6.5)	-0.6%
Other A&G Costs														
IT: Direct & Allocated	7.2	11.5	12.1	10.5	12.9	1.3	3.7%	266.0	251.2	255.6	250.1	250.1	(1.1)	-0.1%
Corporate Cost Reductions	-	-	(0.5)	(5.5)	(3.4)	(3.4)					(15.9)	(17.3)	(17.3)	
Other Membership Costs	2.0	2.5	2.8	3.1	3.3	0.7	9.0%							
Incentives	11.3	16.0	16.3	19.4	8.5	(7.4)	-18.9%							
Severence	2.1	0.7	0.3	-	-	(0.7)	-100.0%							
Regulatory Fees	4.4	6.6	6.1	6.5	7.3	0.7	3.5%							
General Plant Maint.	1.3	1.6	2.8	2.7	2.6	1.0	17.2%							
Total PTO to A&G	4.5	5.8	4.6	4.7	4.9	(0.8)	-5.1%							
Benefits (net of capital allocs.)	35.8	42.0	48.9	58.8	60.4	18.5	12.9%							
Corp Allocations	(1.4)	(3.9)	(6.4)	(5.7)	(6.2)	(2.3)	16.7%							
Revolver Fees, Margin Net Int., & Broker fees	-	3.0	-	-	2.5	(0.5)	-5.7%							
Subtotal	67.4	85.8	87.0	94.5	92.9	7.1	2.7%							
TOTAL A&G	120.4	143.2	144.1	152.8	156.8	13.6	3.1%	640.4	629.9	618.4	599.1	605.0	(24.9)	-1.3%

	HR Lean Processes Complete:	Description:
1	Employee Action Form	Standardize and simplify process; increase automation to improve processing and wait time
2	Drug/Alcohol Program	Utilizing technology and existing vendor, a reallocation of tasks, and changes to program structure
3	Job Posting Improvement	Standardize process for hiring specialist and leverage technology for automation
4	Position Requisition	Streamline position requisition process and online tracking to reduce time spent on process and the time it takes to fill positions
5	Manual Benefit Adjustments	Standardize, streamline and simplify process through automated adjustments; reduce dependency on single point of contact
6	Leaves: Phase I	Standardize and simplify process, clarify roles between business units and increase compliance assurance
7	OD&L Training Administration Process	Reduction in process steps and time related to administration of company-wide training
8	Payroll Cycle Processing	Combination of hourly and salaried pay cycles to reduce payroll process time
9	Disposition of Records in RIM	A reduction in time and steps involved in determining what records have met disposistion requirements.
10	HROP's Voluntary Reduction in Workforce	Standardize, streamline, and further automate steps involved in HR's reduction in force process
11	Vacant Position Evaluation	Examine vacant positions for possible elimination through process simplification, leveraging technologies and outsourcing
12	HR Administration (PO/REQ)	Standardize how purchase orders are requested and created in HR organization
13	Driving Administration	Eliminate redundancies in reporting and administrative duties; improve tracking of employees
14	Customer Contact New Hire online-training	Portion of the new hire course at the Customer Call Center is moved to online format to reduce instructor training time
15	CIS Pro Update Process	Eliminated steps and redundancies involved in authorizing CIS Pro change requests (Customer Call Center)
16	HR Communications (2-day Kaizen)	Streamline the intake process and eliminate obsolete database to increase productivity
17	Retirement Process Review	Streamlining of steps involved in retirement processing
18	Deferred Tuition Process	Streamline tuition payment process
19	Payroll: Adjustment Calculations	Reduction in manual adjustment calculations to improve processing time
20	Staffing: Onboarding	Improve employee welcome process through a web based solution
	In Progress:	
21	Leaves: Phase II	Improved process for reassignment of workers with permanent restrictions
22	Staffing: Job Offers	Streamline, standardize, and utilize technology to reduce process time for producing job offers
23	Apprenticeship Program (wrapping up)	Streamlining of administrative/reporting process involved with the program

Exhibit 1003C

Confidential

Exhibit 1004

PGE's Insurance Policies

Insurance Policy	Description
All Risk Property	PGE's main property insurance program is led by FM Global and insures PGE's property such as power plants, substations, office buildings, etc. from "all-risks" of direct physical loss or damage (including boiler and machinery), subject to policy exclusions, caused by perils such as fire, explosion, lightning, wind, ice, hail, flood, earthquake, and certain acts of terrorism. This policy specifically excludes coverage for PGE's transmission and distribution property as well as PGE's renewable projects. Under this program PGE maintains coverage limits of $800 million with a $2.5 million deductible.
Renewable Property	The property insurance program for PGE's renewable assets is currently placed in the London market. Operational All-Risk coverage for these assets, including both wind and solar, are insured to their combined full replacement value of $950 million and carry a $0.15 million deductible
Director's and Officer's Insurance	Directors and Officers ("D&O") Liability Insurance shields PGE's directors and officers against the normal risks associated with managing the business. The insurance premiums requested in this case are reasonable expenses that are necessary to attract and maintain qualified and competent directors and officers and they provide a direct benefit to PGE's customers. Currently PGE purchases $140 million in D&O insurance limits with a $1 million SIR. The limits purchased are reasonable and necessary and consistent with the standard practice of the utility industry. The lack of an appropriate level of D&O insurance would make it difficult for PGE to hire qualified and competent people for positions at the director and officer level. In addition, lack of appropriate D&O limits would provide a significant motivation for our experienced directors and officers to seek employment elsewhere. Subjecting the Company to the potential of such adverse outcomes is not in the best interest of PGE's ratepayers.
General & Auto Liability	General and Auto Liability insurance covers PGE's legal liability from claims resulting from bodily injury or property damage arising out of PGE's operations, including the use of company vehicles. Given PGE's contact with its customer's premises and the dangerous nature of its operations, this insurance is of paramount importance. PGE maintains coverage limits of $160 million with a $2 million self-insured retention.
Nuclear	PGE is required by the United States Nuclear Regulatory Commission to maintain nuclear liability coverage for the on-site storage of its spent fuel until such time that the radioactive materials have been removed from the Trojan site. The coverage consists of three policies (1) The Facility Form insuring PGE's legal responsibility for damages because of bodily injury, property damage, or covered environmental clean-up costs caused by the Nuclear Energy Hazard during the policy period and reported within ten years of the policy termination. (2) Master Worker insuring PGE's legal obligation to pay as damages because of bodily injury sustained by a "worker" and caused by the nuclear energy hazard. "Worker" refers to a person who is or was engaged in nuclear related employment; (3) Suppliers and Transporters covering incidents caused by radioactive waste materials stored either temporarily or permanently at off-site locations not owned/operated by the insured.

Insurance Policy	Description
Fiduciary	Fiduciary Liability insurance provides protection for officers and employees for both breach of fiduciary duties and other wrongful acts in the administration of employee benefits programs. This program is made up of total limits of $50 million with a $0.25 million SIR
Aviation	This policy insures the helicopter's hull value from physical damage and provides $20 million of liability coverage in operating the aircrafts during PGE's line patrol operations
Network Security & Privacy Liability (Cyber)	The policy has several insuring agreements, providing coverage for: (1) damages and claims expenses due to theft, loss or unauthorized disclosure of personally identifiable non-public information or third party corporate information, (2) costs incurred to comply with a breach notification law, and (3) claims expenses and penalties in the form of a regulatory proceeding resulting from the violation of a privacy law such as HIPPA, FTC. PGE purchases a limit of $10 million with a $.25 million SIR
Fidelity & Crime	Insures losses incurred by PGE or its employee benefit plans as a result of the dishonest acts of employees, including embezzlement, forgery or the theft of money or securities. The policy has a $10 million limit and $0.5 million deductible. This coverage is typically excluded under most All-Risk Property policies and must therefore be purchased under separate cover
Worker's Compensation	The State of Oregon requires PGE to maintain excess coverage to protect itself from catastrophic losses to employees arising out of and in the course of employment. This coverage sits above PGE self-insured workers' compensation program.
WIES	The WIES program functions as a Joint Venture program providing a single mechanism to respond to inter-utility incidents. This coverage minimizes claim and legal expenses and assists in maintaining customer goodwill. The current insurance program is the result of a risk pooling effort among a group of western utilities for spreading the risk of liability incidents that involve more than one electric system. The policy limit is $9 million with a $1 million SIR.
Surety Bonds	In the course of doing business PGE must procure and maintain a number of surety bonds throughout the year. These bonds allow PGE to do work for various state and city governments and agencies and are a requirement for maintaining a form of collateral for self-insuring its Workers' Compensation obligations.

Exhibit 1005	
2014 Proposed Research &Development Projects	
Project Synopses	Cost
Electric and Electric Storage	
EPRI Targets: Battery, Demand Response & Distributed Energy Resources Description: By 2014, PGE expects to be in the position to engage EPRI in the research areas of energy storage via batteries, demand response and distributed energy resources on an integrated basis. It is also likely that PGE will be in a leadership role due to present aggressive R&D in these topical areas. Benefits: Nonetheless, the advent of cheaper energy storage solutions as well as increased penetration of demand response and distributed energy resources would argue easily for PGE to participate with its peers in these areas of research and development cogent to the electrical utility industry. Risks of Non-Participation: Whether leading or in a peer position, PGE and its customers would benefit from the nascent integration localized energy storage, demand response and distributed energy integration programming.	80,540
Second Life Application – EV Batteries Description: This is an R&D demonstration project to showcase the second life use of a Nissan LEAF battery by placing it in a quick charger, tentatively planned at the World Trade Center. Nissan would provide the batteries, a quick charge manufacturer (e.g. Kanematsu) would be recruited to provide a quick charger (although there is a possibility of using a new Nissan quick charger). PGE would make the necessary arrangements for hosting the project and providing the necessary improvements to the electric infrastructure needed to support the demonstration. Benefits: It is currently estimated that as much as 80% of the vehicle battery life may remain for other uses and duty cycles. This project would test and demonstrate one such possible use. Risks of Non-Participation: PGE and its customers will gain intelligence from data on second life use of Li-ion batteries systems that could be applied to demand response applications. Learnings will lead to possible demonstration projects to get power to quick chargers in rural areas of the service territory.	53,692
Vehicle to Home Concept (V2H) Description: The "V2H" system would enable energy stored in an electric vehicle battery to be used in residential homes; for example, the Nissan Leaf's 24 kW lithium-ion battery pack should be able to provide the typical household with enough electricity for up to two full days, when the battery is fully charged. This project proposes to devise and integrate a power control system that would be supplied by *Nichicon*, a company based in Kyoto that is looking for a US manufacturing site. Nissan would modify a Leaf for the demonstration at their expense.	67,115

Benefits: This project will help determine the effectiveness of an electric vehicle acting as a back-up power source in the event of a power outage or when needed to meet critical peak. The project also hopes to integrate time of use (TOU) price signaling capabilities for vehicle smart charging. Risks of Non-Participation: It is anticipated that PGE would host and provide the host vehicle for the demonstration, as well as manage the project and evaluate it. PGE would also be responsible for developing the mechanism for communicating price signals. The learning from this project would be a first step in assessing feasibility of larger scale demonstrations.	
EcoDistrict Project, District Energy Development Description: This project proposes a partnership with the Portland Development Commission on district energy in one of Portland's planned "Eco District" projects. The most likely candidate would be the North Macadam expansion of the South Waterfront. PGE would build upon a feasibility study currently underway to determine the viability of a 5-10 MW cogeneration system in conjunction with the planned district heating and cooling system. PGE staff time and outside expertise required to complete a feasibility assessment. Benefits: The benefits of integrating distributed generation (as opposed to traditional system upgrades) would be modeled and analyzed for cost-effectiveness, durability, operational concerns and applicability. Risks of Non-Participation: More community based energy projects are emerging that are closely related to distributed sources of power generation, energy storage and even leveraging existing infrastructure for energy efficiency or generation purposes (e.g., water pipe turbines, ground source or groundwater source or water main heat exchange for heat pump technology).	40,270
"Uber Water Heater" Project Description: This project seeks to evolve a new and very efficient design for water-to-water heat exchange. The design is presently proprietary to PGE but preliminary, supportive computations and verification has been done in collaboration with Portland State University's Power Engineering Group. Benefits: This proposal seeks to continue this design work through prototype build and testing. More significantly – the project will seek to demonstrate the technology through a retrofit in one all electric home in PGE's service territory. Risks of Non-Participation: More community based energy projects are emerging that are closely related to distributed sources of power generation, energy storage and even leveraging existing infrastructure for energy efficiency or generation purposes (e.g., water pipe turbines, ground source or groundwater source or water main heat exchange for heat pump technology).	80,540
Load Control EV Charging Station Demonstration Description: This project would team PGE staff with an EV charging station manufacturer and software tool provider to develop a prototype that can control charging load in real time. Benefits: Two benefits would be explored: (1) the reduction of utility demand charges by	34,900

controlling total EV charging load, and (2) the creation of a new demand response resource by controlling EV charging load. Researchers from PSU's Power Engineering Group would also support this effort by providing fundamental research and documentation. Risks of Non-Participation: It is perhaps inevitable that internal combustion engines in vehicles will be replaced by all electric drive systems. This project helps demonstrate an underlying feature of how supportive and necessary infrastructure could evolve to help accommodate that future.	
Green Electric Vehicle (EV) Charging Integration Description: This project would team PGE staff with Xatori or another application developer to demonstrate how customers can integrate their EV charging habits with their preference of using renewable power as a transportation fuel. Benefits: This project supports the larger EV vision of powering transportation using electricity generated from a PGE power generation mix that is becoming increasingly renewable in its character. Risks of Non-Participation: It is perhaps inevitable that internal combustion engines in vehicles will be replaced by all electric drive systems. This project helps demonstrate consumer acceptance and market acceptance of how supportive and necessary infrastructure features could evolve to help accommodate that future.	13,425
Home Battery Backup Demonstration Description: This project seeks to demonstrate an AQUION ($NaMnO2$), 25 kWhr (about 7 or 8 kW) battery for home installation on a manual switch on/off basis in order to test the new chemistry type in the battery and to understand the basic electrical problems (NEC) that may evolve, performance, durability (supposedly 20 years), customer acceptance and feedback. Benefits: This is a very stable battery capable of operating with a wide voltage range; in conjunction with the battery an appropriate inverter will also need to be tested to assess whether the system can live up to its billing. Risks of Non-Participation: More community based energy sources are emerging that are closely related to distributed sources of power generation, energy storage and even leveraging existing infrastructure for energy efficiency or generation purposes (e.g., water pipe turbines, ground source or groundwater source or water main heat exchange for heat pump technology).	53,700
Demonstrating a Battery buffered, Solar & Wind Charging Station Description: This project would retrofit the OMSI electric vehicle (EV) charging site with a battery buffered DC Quick Charging station. The battery would utilize wind and solar power as its primary charging sources. Benefits: The demonstration would be unique in the Pacific NW and it is intended to couple the demonstration with exhibit-quality display panels that would indicate when the battery is charging with wind power or with solar power, in addition to showing the automobile charging cycle.	34,900

Risks of Non-Participation: It is perhaps inevitable that internal combustion engines in vehicles will be replaced by all electric drive systems. This project helps demonstrate one facet of how supportive and necessary infrastructure could evolve to help accommodate that future.	
Inductive Charging Demonstration Description: This project would demonstrate inductive charging at three potential sites: (1) with a PGE fleet car, (2) with a public transit vehicle (such as one of the parking shuttle vans at the Portland International Airport) and (3) with an electric forklift truck. Benefits: This broad array of demonstration would allow users to see and evaluate the potential and any concerns around the inductive charging approach. Risks of Non-Participation: It is perhaps inevitable that internal combustion engines in vehicles will be replaced by all electric drive systems. This project helps demonstrate one facet of how supportive and necessary infrastructure could evolve to help accommodate that future.	32,315
Single Phase DC Quick Charging Station Demonstration Description: This project would utilize battery storage to enable a DC Quick Charger to operate where only single-phase power is available. Currently, all DC Quick Charging equipment requires three-phase power. Benefits: This project would demonstrate the potential to "fill in the gaps" in outlying areas of the grid that are, nonetheless, popular travel routes. Risks of Non-Participation: It is perhaps inevitable that internal combustion engines in vehicles will be replaced by all electric drive systems. This project helps demonstrate one facet of how supportive and necessary infrastructure could evolve to help accommodate that future.	26,850
Total Electric and Electric Storage	**518,247**
Energy Efficiency	
Ductless Heat Pump Heat Recovery Whole House Ventilation Description: Ductless heat pumps are continuing to gain popularity and market share in the Pacific Northwest. Now that the region's installation contractors are better trained and familiar with the equipment, NW Ductless project (NEEA) is beginning to influence how systems are sized and specified for homes in an effort to reduce installation costs and thus improve measure cost effectiveness. Their "One and done" marketing campaign is driving participating utilities and Energy Trust to adopt new rules whereby incentives will be eliminated for customers that chose systems with more than two indoor zones. This is fine for single level, smaller homes 2000 sq. ft. or less, but gives the designer/contractor pause for typical homes (above 2000 sq. ft.) or multi-story homes. Benefits: The biggest concern is the potential for lack of proper airflow throughout the home which could lead to inconsistent temperatures and at worst areas with cold, moldy walls. One very promising solution is to use an additional system that is dedicated to moving air through the home – i.e., whole house heat recovery ventilation (HRV) system. HRV systems tend to require very little input wattage, but operate continuously to ensure good air mixing (churn) within the home and good, even temperature distribution.	13,423

Risks of Non-Participation: This study would examine whether these intuitive performance assumptions are indeed true. PGE proposes to work with OIT engineers and students to do finite element analysis (air disbursement modeling) on the prototypical home as characteristically defined by the NW Regional Technical Forum. OIT would study the effects of ductless heat pump system indoor unit placement and quantity, HRV supply and return capacities, register quantity and placement, etc. in an effort to determine: 1) How uniform temperatures may be achieved throughout the home 2) The optimal flow rates to achieve #1. 3) Effect on unit and register placement and quantity 4) The optimized system design for first cost 5) The optimized system design for ventilation effectiveness 6) The optimized system design for temperature (comfort) 7) The optimized system design for energy efficiency 8) The optimized system design that best meets utility performance criteria (to be defined around CPP, DR, identified undersized transformer replacement, etc.)	
Total Energy Efficiency	**13,423**
Miscellaneous	
OSU – Cascadia Lifelines (Seismic) Research Project Description: There is increasing recognition of the major threat sitting offshore the Pacific Northwest coastline: the Cascadia Subduction Zone (CSZ). The Department of Oregon Geology and Mineral Industries (DOGAMI) estimates that in a CSZ earthquake, thousands of Oregonians would be affected and ODOT predicts a debilitating loss of mobility, shutting down major parts of U.S. Highway 101, Interstate 5, and all routes to the coast. Estimates indicate that ODOT alone must invest more than $1 billion to begin to mitigate this risk. Recent work on Oregon Resilience Planning indicates that other lifelines are even more vulnerable. Benefits: As a leading provider of electric power to the people of the Oregon, PGE proposes to take steps to improve our earthquake resilience. PGE has been approached by OSU with a highly leveraged opportunity to participate in this type of inquiry. Many of Oregon's other lifeline providers, such as gas utilities, water and sewer utilities, fuel providers and ports, face similar challenges as PGE with an aging infrastructure that was built before anyone fully understood the seismic risk we face. And, a lot of what we understand regarding methods to mitigate seismic risk was developed for much shorter duration earthquakes, typical of those experienced in California, not the three- to five-minute earthquakes seen in Chile and Japan over the last two years, and as is expected in Oregon. This is why Oregon State University, in collaboration with the Pacific Earthquake Engineering Research Center (PEER), is initiating the Cascadia Lifelines Program. Risks of Non-Participation: OSU proposes to form a research consortium to collectively conduct the necessary research to enable our lifeline providers to implement value- and cost-informed decisions to mitigate the risk facing the Northwest. The Cascadia Lifelines Program can provide essential and unique engineering solutions for lifeline providers, including cost-effective retrofit strategies for our distinct infrastructure subjected to long-duration shaking, improved prediction of ground-shaking specific to Oregon conditions, predicted seismic behavior of soils unique to the Willamette Valley including the liquefaction potential, and system optimization of interdependent lifelines. The impact of this r research will be a cost-	26,850

effective approach to increased resilience, resulting in improved business continuity for PGE's customers.	
Total Miscellaneous	**26,850**
Renewable Projects	
Biglow Wind LIDAR Forecasting & High-Reliability System Description: LIDAR is a proven technology intended to compliment the primary ultrasonic anemometer, providing wind sensing and yaw-control for a utility-scale wind turbine. A proposed system provides 10-20 seconds (proven) of advance response for controls and correction of yaw and resource scheduling. Project would test for 6 months, two turbines at PGE's Biglow site. The project would acquire and install 2 LIDAR anemometer systems, one for each turbine type at the Biglow site. The data from LIDAR platform communications will be integrated to the evolving PGE Smart Power Platform, allowing 10-20 second advance scheduling of wind following and control system resources. Benefits: (1) New prediction of wind resources to complement PGE Smart Power platform services, including wind following and optimal smart-grid scheduling for the Energy Storage; Facility (utility scale battery) and other Smart Power resources (demand response, DSG); (2) Investigating integrated yaw control improvements on each turbine system and (3) Investigating possible increases in generation capacity factor per turbine. Risks of Non-Participation: PGE would delay potentially significant improvements for its Biglow Wind Farm in terms of better wind prediction which in turn would lessen ancillary service requirements.	123,500
Torrefaction for Biomass Description: The Boardman Biomass Project will require torrefied biomass to displace the present Powder River Basin coal. Torrefaction is pyrolysis at a temperature range of 250 to 350 degrees Celsius. The process will char biogenic biomass and make it pulverizable for use in the Boardman Power Plant. Benefits: Its use will include the following in support of the test burn in 2014 – (1) Assess effects on Boardman pulverizers and conveyance equipment when using torrefied biomass; (2) Test impacts on the firing system and (3) Allow assessment of plant performance including emissions analysis. Risks of Non-Participation: This testing and R&D will be necessary as torrefied biomass with its different energy content and chemical makeup will need to be fully assessed regarding potential impacts on the Boardman boiler operation as well as in characterizing residual slag and ash contents.	188,000
Arundo **Agronomy, other Regional Biomass Studies** Description: This project proposes to continue development of R&D in support of *Arundo donax* as a high productivity energy grass; other regional sources of biogenic biomass as well	215,000

as other biomass supply chain aspects. This nascent supply chain creation will require extended R&D into 2014 and beyond. Benefits: Should the test burn at the Boardman Power Plant be successful in 2014 – the current project schedule calls for increasing from 100 to 4,000 acres of planted *Arundo*. This will be unprecedented for this perennial energy grass. Risks of Non-Participation: Based on earlier R&D efforts in 2011 and 2012 this significant increase in scaling will need to be supported by concomitantly increased agronomic testing, optimization and problem solving to ensure a smooth introduction of a new and substantial biomass-based supply chain into the agricultural community in eastern Oregon.	
OSU Biglow Canyon Wind Optimization Analysis Description: Oregon State University is analyzing actual energy production data to optimize the performance of Biglow Canyon wind turbines. The analysis includes comparison of wind turbine output with expected output based on meteorological tower data and the supplier's power curves. In addition, the analysis assesses the differences between adjacent wind turbines and outlier turbines in a string. Benefits: Optimizing Biglow Canyon will improve renewable energy production for PGE customers and maximize recovery of Production Tax Credits. Dr. Stel Walker is conducting this research and it is proposed to continue it into 2014. Risks of Non-Participation: Via its IRP process, it is expected that PGE will put more utility scale wind power onto its grid. Methods to improve or optimize individual turbine locations as well as turbine strings should rely on lessons learned from earlier installations to ensure improved optimization of wind farm siting and operation.	13,425
OSU Wave Energy Description: This project provides continuing support for the expansion of wave energy resource evaluations being used to assess renewable energy potential in the Pacific Northwest. This work is supervised by Drs. Annette von Jouanne and Ted Brekken and their colleagues at OSU. Advancing wave energy research may provide the benefit of encouraging new project development in Oregon especially if wave and wind power resources can be optimally matched. This would allow increased diversity in PGE's renewable resources portfolio. Oregon State University is the prime location to conduct ocean energy research, due in part to strategic facilities on the Corvallis campus (Wave Research Lab), linear test-bed (buoy testing device), Hatfield Marine Science Center (Yaquina Bay, OR), and OSU's proximity to a NNMREC demonstration site off the coast of Newport, Oregon. Benefits: As a result of the Oregon Legislature passing a Renewable Portfolio Standard (RPS) in 2007 and in support of PGE's Integrated Resource Plan (IRP), PGE will be actively pursuing significant new renewable resources to satisfy State renewable energy requirements. Risks of Non-Participation: Research on wave energy technologies will provide important options. Support of OSU's research and development of Oregon wave energy should provide significant benefit in accomplishing this goal.	10,740

OSU Wind Energy Integration & Storage Description: Oregon State University's (OSU) Wallace Energy Systems and Renewables Facility (lab) is advancing research on wind energy integration through more effective coordination of traditional generation resources and energy storage systems. This research by Dr. Annette von Jouanne and her colleagues will help to optimize wind energy production while also increasing the predictability of wind farm outputs. The proposed project includes advanced "life extending control" and coordination of multiple energy storage solutions to maximize cost effective energy production, reduce dependency on hydro-power resources, reduce spinning reserve and peak load problems, increase transmission capacity and help stabilize power quality disturbances. Benefits: Comprehensive modeling will be performed, in addition to using an in-lab grid as an essential hardware verification system. Advanced forecasting tools will be developed leading to new operating protocols and guidelines to ensure more reliable system operation. With the increased diversification of the power system, advanced approaches to monitoring and optimizing the mix of dispatchable and non-dispatchable generation will be researched, to increase the efficiency of generation and to mitigate the negative impacts of large scale integration of variable resources. Risks of Non-Participation: Effective use of energy storage can provide increased load leveling capability and can reduce reserve requirements. More effective control of energy storage systems can improve the predictability of wind plant outputs, and decrease the cost of wind integration. Finally, great benefits can be realized through the proposed research on determining the optimal mix of wind technology integration and energy storage technology (single and hybrid/mixed energy storage systems).	10,740
Complementarity of Wind and Solar at David Douglas High School Description: Students in the Advance Electronics class at David Douglas High School (DDHS - Portland, OR) are currently conducting an R&D project to determine how complementary a solar photovoltaic system is to a wind turbine's output. This is one of the few locations in Oregon where there is co-located solar and wind installations. The Whisper 100 wind turbine and PV panels are mounted on a mast on the High School's property. The generated energy is stored in Surrette-Rolls batteries for use in the electronics lab. The project is supervised by Mr. Bill Ekroth, Electronics Instructor - David Douglas High School. Benefits: The data developed in this R&D project by DDHS will be beneficial in understanding integration of intermittent renewable resources on the PGE grid. Risks of Non-Participation: It is likely that in central and eastern Oregon, there is/will be the potential for significant wind and solar installations – if not co-located than at least in fairly close proximity. It would be useful to assess complementarity at some scale even west of the Cascades to better assess this potential.	2,680

Evaluative metrics and verification for Transactive Control Architecture Description: PGE has evolved substantial capacity in the development of Transactive Node (TN) Control Architecture in support of learning systems (computational intelligence) that optimize load and cost between an energy provider and an energy user. Nonetheless, there are many aspects that bear continued refinement including assessing and specifying conditions where it is safe to operate a section of a distribution system under TN control. Benefits: Further exploitation of other data inputs to the transaction are possible and even desirable such as including important environmental factors like temperature, irradiance, wind. This project addresses these and other developmental questions in partnership with Portland State University's Power Engineering group. Risks of Non-Participation: Evaluative metrics still need development in order to assess whether the Transactive Node software actually delivered optimized economic dispatch.	34,900
Inverter Usage and Grid Interaction with increased PV Penetration Description: As solar PV continues to increase, the associated power inverters will have a more prominent interaction with the electrical grid. This project assesses the types of functions that inverters must begin to assume beyond power conversion in order to best facilitate continued high penetration of photovoltaics. For example, can inverters be designed to serve as distribution-scale static synchronous compensators (STATCOM) providing power quality and volt/VAR services? Benefits: Establishment of more clustered solar Photovoltaic installations lends some urgency to improve both PGE's understanding of the role of inverters and, to the extent possible - to assess abilities to exploit their presence for other uses on the grid and to improve the reliability of the grid itself. Much of this work will be done in collaboration with the Portland State University Power Engineering Group. Risks of Non-Participation: Solar power penetration in a distributed format is expected to increase with attendant grid integration concerns; this research helps PGE better understand how to optimally accommodate this future.	32,215
Modeling Wind Turbine Wake Effects using the PSU Wind Tunnel Description: This project seeks to determine the decrease in wind turbine wake effects by changing the turbine rotor rotation – from clockwise to counter clockwise – for each adjacent wind turbine in an established string – potentially at PGE's Biglow Canyon wind farm. All modeling in this R&D project is to be performed at the Portland State University, Mechanical Engineering wind tunnel conceived and operated by Dr. Raul Cal and his colleagues. Benefits: Using data from PGE's Biglow Canyon, this project will model the wake effects for Phase 2 along the western edge of the Project property; then simulate the counter rotation of adjacent wind turbines to estimate the change in wake effect on subsequent rows of turbines. The subsequent analysis will focus on the change in wind turbine production in MWh and lateral stress in foot-pounds of force applied to the wind turbine tower base.	16,110

Risks of Non-Participation: This work complements a future where PGE is expected to own and operate additional large scale wind farms. Minimizing wake effects in a large wind turbine array would reduce wear and maintenance cost over the life of the project. This R&D project would help to quantify specific changes in wake effects by counter-rotating adjacent wind turbine rotors.	
Educational Program for In-Home Display w/ Energy Tracker Description: The project seeks to develop and pilot a programed learning guide / tool aimed at 5th graders but administered by the 5th grade science teacher with PGE support. In-home display would be added to the homes of students (of one class). The programmed learning guide would have simple exercises that use both energy tracker and the in-home display over a period of about 3 weeks. Goal would be a "report" at the end of the exercise that itemizes how the home uses energy and its cost; also the list of the top ten devices that use the most power when operating. Benefits: The overall benefits would be to derive a curriculum that teaches students the difference between power and energy as well as value (benefit minus cost) of energy used in the home. Risks of Non-Participation: As smart grid technologies penetrate to the home or commercial space even beyond a "smart meter" it would be desirable to assess how these can be integrated more fully and optimally into PGE's grid operation even at the consumer level. Acceptance of these technologies and penetration will depend to some (if not large) degree on consumer and user education regarding the benefits and costs.	64,400
Total Renewable Projects	711,710
Smart Grid – Smart Technology	
Oxford Substation – Rural Feeder Distribution Automation Description: Five automatic switches have been installed on the Rural Feeder with funding from the Salem Smart Power Project which used highly leveraged funding from a US DOE ARRA grant. These switches will be used in commissioning, testing and start-up of the energy storage system. The switches are S&C **Intellirupter** switches and are unique in that they have a high level of functionality. If used solely for the Salem Smart Power Project, these switches will be underutilized. This project proposes to utilize these switches at a higher level functionality for distribution automation. Research opportunity components include: Benefits: This project anticipates growth of Smart Grid systems and integration components with renewable power and distribution systems; it supports efficient operations through increased reliability on PGE's Rural Feeder (SAIFI, SAIDI); faster outage recovery and safer operations for line crews. Risks of Non-Participation: Not utilizing these switches will delay PGE's understanding of an important Smart Grid feature, i.e., "rapid fault detection and line sectionalizing" as a prelude to self-healing.	59,060

Street Light PV integrated into Salem Smart Power Center Description: This project proposes to install 30 street light micro-inverter solar panels in the Salem Smart Power Project feeder region or an equivalent capacity. The demonstration is a component of PGE's commitment to better integrating smart grid and renewable energy opportunities. The plan presently includes installation of 30 Petra Solar streetlight panels and micro-inverters in the Salem Smart Feeder region. Data integration is from IEEE 802.15.4 compliant communications to the evolving PGE Smart Power Platform and will allow remote configuration via substation. Benefits: The project will provide regional grid voltage measurement for data collection and forecasting needs through use of synchrophasor technology. Also, it provides additional resources for managing reactive power at the distribution layer. Risks of Non-Participation: PGE will delay adding this level of necessary smart grid complexity to its system.	75,168
Smart Power Platform "Sonification of electric usage" Description: Sonification is a proven technology for signal processing from raw data into audible music. Recent successes in the UK and at US universities have demonstrated transformation of electrical usage patterns into an audible waveform (not 60 Hz buzz – but real music). This project seeks to investigate changing a customer's real-time energy usage into a novel musical format which is customizable for a customer's musical interests. Data will be collected in real-time from a home energy management system and transformed via an application into music. It is well known that many customers are not "in tune" with their own usage, and the electric bill is not a sufficient channel to maintain customer interest in usage metrics. This project would explore methods and complete a prototype system. In detail, the project would acquire one energy home management system and connect it to a workstation computer and an electrical device (a fan is sufficient) with a usage meter at the plug. An application would be developed in collaboration with university researchers to sonify the real-time electrical signal into a custom-configurable musical work. Benefits: This project seeks to understand whether there is a benefit of linking the customer to their own usage in a new way that may prove both unique and exciting as a form of customer outreach and for keeping interest in electrical usage data on a daily basis. Risks of Non-Participation: It is well accepted that the last frontier of successful energy efficiency programming will require human behavior engagement. Sonification is akin to other behavioral efforts (e.g., game playing) to get past this boundary.	44,564
Smart Power Synchrophasor Reliability & Fast Command System Description: This project would add Synchrophasor system components to PGE's Salem Smart Power feeder system and Smart Power Platform supervisory distributed resource controller. Synchrophasor measurement systems are a proven method for increasing system reliability; performing distributed power factor regulation for system efficiency and financial benefits; improving distribution automation to reduce SAIDI and SAIFI and to improve safety, efficiency and customer relations; the system would further integration of smart grid resources	91,280

onto PGE's grid. The project plan includes the purchase and installation of three (3) phase measurement units (PMU's) at strategic locations on the feeder. Concurrently there would be the purchase and installation of SEL Synchrowave software to gather phase measurement data from the PMU's to help make economic and operating decisions; finally, the collected data will be integrated into PGE's nascent Smart Power Platform for informing PGE's Smart Power supervisory control system of real-time feeder data via fast messaging, including real power, voltage, frequency, and phasor measurements. <u>Benefits</u>: The project will also investigate and research best methods of transforming the data into actionable commands to increase reliability and efficiency, within the Smart Power Platform controller. Achieving this level of highly automated data acquisition and response will allow PGE to begin exploring the concept of grid "self-healing" on a sizable feeder line. <u>Risks of Non-Participation</u>: The Salem Smart Power Project is a highly leveraged (financially) demonstration. Adding advanced grid monitoring via synchrophasors permits a natural evolution for the concept of "self-healing" grid and in this case at a significant level of scale.	
Big Data Analytics Project <u>Description</u>: This project seeks to develop a collaborative partnership between PGE and a major player in the emerging 'Big Data' space (e.g. GE, IBM). This project will help demonstrate the usefulness of big data analytic capabilities in improving system planning and reliability, outage restoration, and other operational features. New analytic structures will be required in order to be responsive and proactive to increasing penetration of smart grid concepts into PGE's system. <u>Benefits</u>: It is envisioned that PGE would learn about efficient data analytics and how they could be a useful tool to examine and understand large amounts of data quickly to make effective business and operational decisions on behalf of its customers. This would be particularly true in the use of very short time interval data. <u>Risks of Non-Participations</u>: The project envisions that a 'Big Data' provider/integrator would partner with PGE on a trial demonstration project requiring access to PGE's systems and staff resources for ongoing implementation and demonstrations.	80,538
Home Communicating Thermostat Demonstration <u>Description</u>: This project works with a Programmable Communicating T-Stat (PCT – aka "Smart Thermostat"). The goal is to research available models; pilot 2 to 3 in actual home usage for demonstration. <u>Benefits</u>: As part of the demonstration the project will filter the selected model(s) so as to be compatible with PGE's smart meter and or other network communications pathways that PGE ultimately uses. <u>Risks of Non-Participation</u>: As smart grid technologies penetrate to the home or commercial	42,954

space even beyond a "smart meter" it would be desirable to assess how these can be integrated more fully and optimally into PGE's grid operation even at the consumer level.	
SEGIS-AC (Solar Energy and Smart Grid Integrated System – Advanced Concepts) Description: This project is focused on creating cost-effective technologies to mitigate potential grid reliability issues associated with solar installations. This includes testing both distribution and transmission level voltage impacts mitigation through use of a 500 kW battery. SEGIS-AC aims to showcase technologies that use advanced voltage control functions developed in compliance with the EPRI Smart Inverter Initiative. Advanced Energy (Bend, OR) is the lead project manager partnering with PGE and others. PGE is in discussions with Saft Batteries, LG Chem, Panasonic, Samsung and Mitsubishi Heavy Industries to potentially be the battery supplier on this project. Benefits: The project is predominantly funded by the US DOE SunShot Initiative Project which provides funding over a three year cycle. PGE would be responsible for 20% of the 2014 funds and 50% of capital cost sharing. PGE labor resources will be utilized over the span of the project through project management and ongoing interactions with Advanced Energy, the battery supplier, etc. Risks of Non-Participation: Success in the project will help further help develop, demonstrate and commercialize load ramp control and solar smoothing through energy storage, islanding detection and system protection, and distributed automation using synchrophasor technologies.	42,950
Total Smart Grid Projects	436,514
Total All 2014 Projects	$1,706,744

Exhibit 1006

Note: Cost Savings and Avoidance amounts are based upon Utility Purchasing Management Group's (UPMG) definition which is described below.

COST SAVINGS (**Cost reductions attributed to Purchasing) - The reduction in the cost of the same goods or services compared to the previous price paid, i.e. savings that can be used to reduce company budgets, whether or not they are actually reduced. Quantification of savings, ideally, should be based on some baseline agreed upon by the Purchasing organization and its internal client.** **>> Typically, the following activities/measure are used to calculate Cost Savings:**
1. Difference between previous and current price paid
2. Product substitutions resulting in lower total cost
3. Introduction of new supplier or contractor
4. Lower cost resulting from strategic alliances with supplies
5. Freight cost reductions
6. Payment discounts taken
7. Negotiated rebates taken
8. Negotiations with awarded supplier(s) to lower cost
9. Negotiated labor rate reductions
10. Equipment refurbishment as a substitute for new
11. Upfront payments by suppliers ('signing bonus") resulting in lower cost
12. Savings guarantees by suppliers resulting in lower cost

COST AVOIDANCE **- The difference between the price paid for the same goods or services and the probable increase in price that would have occurred without the actions taken to avoid the increased cost, i.e. cost reductions that avoid budget increases.** **>> Typically, the following activities/measures are used to calculate Cost Avoidance:**
1. Comparison of the cost to a probable increase in cost that may have occurred, e.g., as a result of inflation
2. Comparison of the average market cost vs. the awarded supplier cost. Average market cost is the average unit price for all supplier proposals, with the elimination of any outliers.
3. Comparison of engineering or budget estimates to awarded supplier costs
4. The difference between the incumbent supplier's bid and the selected supplier's bid
5. Commodity (or other) price index used to adjust costs.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 262

Cost of Capital

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Patrick G. Hager
William J. Valach

February 15, 2013

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I. Introduction

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

A. My name is Patrick G. Hager. I am the Manager of Regulatory Affairs at PGE. I am responsible for analyzing PGE's cost of capital.

My name is William J. Valach. I am the Director of Investor Relations for PGE. I am responsible for managing the company's relationships and communications with PGE's shareholders and the investing public.

Our qualifications are included at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to recommend PGE's cost of capital and capital structure for the 2014 test year. PGE's requested cost of capital and capital structure is necessary to maintain and improve on its current credit profile for access to the debt and equity markets, to fund its significant capital investments required through its RFPs, and to provide PGE the opportunity to earn a fair return for equity shareholders while keeping its costs reasonable. As Dr. Zepp discusses in his testimony (PGE Exhibit 1200), guidance regarding the appropriate cost of capital is provided by the Bluefield[1] and Hope[2] Supreme Court decisions as well as ORS 756.040.

Q. What are PGE's financial goals?

A. PGE's overall goals include the following:

- Maintaining investment grade bond ratings;
- Accessing financial markets at reasonable terms to provide liquidity for operations and capital expenditures;

[1] Bluefield Water Works v. Public Service Comm'n - 262 U.S. 679 (1923)
[2] FPC v. Hope Nat. Gas Co. - 320 U.S. 591 (1944)

- Achieving an actual return on equity that is commensurate with the return on equity achieved by a group of utilities with similar characteristics, service territory, and business risks; and
- Setting retail prices at a level sufficient to recover prudently incurred costs, including an overall return on utility investment, while being considerate of the economic conditions facing our customers.

Q. What is PGE's requested overall cost of capital for this filing?

A. We request and support a 7.863% cost of capital for the 2014 test year, which is lower than our current authorized cost of capital. This cost of capital includes a 10.00% Return on Equity (ROE) based on the recommendations of Dr. Zepp in PGE Exhibit 1200. This point estimate is for revenue requirement purposes and is based on our recommended range of 7.863% to 8.401 % for PGE's cost of capital and a recommended range of 10.0% to 10.7% for PGE's ROE. Table 1 below shows the recommended cost of the two components of PGE's capital, common equity and long-term debt. Table 1 also shows PGE's forecasted 2014 capital structure.

Q. How did you derive the overall recommended cost of capital?

A. We first estimated the cost of the debt and equity components by considering the range, PGE's risks, and financing needs. We then determined the weighted cost by multiplying the component's cost by its weight (percent) in our recommended capital structure. Finally, we summarized the weighted cost of each component to derive the weighted, or composite, cost of capital. Table 1 below summarizes these calculations.

Table 1
PGE's Weighted Cost of Capital
Test Year 2014

Component	Average Outstanding ($000) [1]	Percent of Capital [2]	Component Cost	Weighted Cost
Long-term Debt	$2,091,400	50.00%	5.726%	2.863%
Common Equity	$2,090,792	50.00%	10.000%	5.000%
Total	**$4,182,192**	**100.00%**		**7.863%**

[1] "Average Outstanding" reflects PGE's projected average values of long-term debt and common equity for 2014.

[2] "Percent of Capital" reflects PGE's long-term targeted capital structure of 50% debt, 50% equity, and is used to calculate PGE's weighted average cost of capital ("Weighted Cost").

Q. How is the remainder of your testimony organized?

A. In the following section, we discuss the effects of regulation, including PGE's power cost adjustment mechanism (PCAM) and decoupling. In Section III, we provide a review of the recent financial market conditions and economic activity. We then discuss PGE's cost of long-term debt, including new and redeemed issuances, in Section IV. In Section V, we discuss PGE's capital structure. Section VI provides our qualifications.

II. Regulation and Cost of Capital

Q. Why is good credit quality important?

A. Good credit quality is critical to secure financing at reasonable rates and to maintain access to wholesale energy markets, especially in today's financial environment.

Q. You mentioned maintaining access to the financial markets as one of PGE's financial goals. Why does PGE need to maintain access to these markets?

A. PGE needs to maintain access to the equity and credit markets to provide cash and liquidity for operations, and to fund our significant capital expenditure program over the next five years, as discussed in PGE's acknowledged 2009 Integrated Resource Plan (IRP), OPUC Docket LC 48, and in our 2011 and 2012 updates. PGE's IRP recommends significant investments in generation facilities and transmission projects. In this filing, PGE has included capital expenditure forecasts[3] of approximately $789.8 million in 2013, $970.4 million in 2014, based on PGE's on-going base business as well as the ongoing request for energy, capacity and renewables proposals and Cascade Crossing transmission project. However, with regard to Cascade Crossing, PGE and the Bonneville Power Administration (BPA) are in the process of pursuing changes to PGE's proposed Cascade Crossing transmission project that might reduce these expenditures. PGE will update its capital expenditure forecast and make any needed changes to its financing plans as new information becomes available. In 2011 and 2012, PGE's capital expenditures totaled approximately $300 million and $303 million. As noted in Section V below, a high level of capital expenditures and related financing needs increases the importance of supportive regulatory actions.

[3] Capital expenditures are not part of PGE's rate base unless the project closes in 2013 or 2014. PGE Exhibit 300 discusses projects that close in 2013 and 2014.

In addition to the requirements of our base business and the RFPs, PGE needs to maintain ready access to the credit markets to enable us to actively manage our debt and credit arrangements in order to take advantage of favorable opportunities for refinancing or restructuring. Through our portfolio management, PGE has historically refinanced debt and renegotiated credit arrangements when prudent, which has benefited customers by lowering PGE's overall cost of debt. By maintaining a strong financial profile and financial flexibility, PGE will be able to preserve its ability to raise capital at reasonable terms under various market conditions.

Q. What impact does regulatory support have on PGE's credit quality?

A. Regulatory policy that supports recovery of prudent costs is essential to maintaining a stable, investment grade credit rating. As discussed in Section V below, this support is especially important given the significant size of PGE's potential capital expenditures and related financing over the next five years.

Both Moody's and Standard & Poor's (S&P) consider regulatory policy a key factor in their determination of a utility's creditworthiness. For example, Moody's places equal weighting on "Regulatory Framework" and "Ability to Recover Costs and Earn Returns" in its assessment of electric and gas utilities.[4] S&P indicates that "[r]egulation is the most critical aspect that underlies regulated integrated utilities' creditworthiness."[5] Key characteristics in the assessment of regulatory environments for both credit rating firms include the consistency and predictability of Commission decisions, as well as the ability for timely recovery of prudently incurred costs.

[4] "Rating Methodology – Regulated Electric and Gas Utilities." Moody's Global Infrastructure Finance- August 2009.
[5] "Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry." Standard & Poor's- November 2008.

PGE's credit ratings are provided in PGE Exhibit 1102.

Q. Have financial analysts noted any concerns regarding regulatory outcomes as they pertain to PGE?

A. Yes. Bank sell side analysts are concerned with the following: "We view the state of Oregon regulatory environment as somewhat historically restrictive to average from an investor standpoint. In our view, constructive regulatory mechanisms highlighted as investment positives are offset by an asymmetric power cost sharing mechanism and historically below-average ROEs awarded in Oregon. We believe POR's next general rate case filing bears watching, as it is planned for early 2013 for new rates effective beginning 2014, and introduces regulatory risks/benefits to the investment story."[6] S&P highlighted a concern that PGE's power cost adjustment mechanism contained provisions that weakened its structure, notably the deadbands and an earning test requirement. The other concern relates to PGE's decoupling mechanism that expires at the end of 2013.

A. Power Cost Adjustment Mechanism

Q. Have financial analysts expressed concerns regarding the PCAM?

A. Yes. Their concerns surround the wide deadband and the asymmetry of benefits allocation, which could result in "meaningful" impacts on PGE's earnings, increasing volatility. Deutsche Bank Research notes that PGE "is not assured full recovery of its fuel and purchased power costs, a relatively rare risk for US regulated utilities as most pass those costs on to customers."[7] JP Morgan notices that "the fuel and purchased power recovery clause authorizes for PGE exposes the company to near term fluctuations in hydro

[6] KeyBanc Capital Markets Energy Industry Research. POR-NYSE. Transitioning to a Rate Base Growth Story. December 4, 2012
[7] Deutsche Bank Markets Research. Small cap growth potential with catalysts. June 5, 2012

conditions in the Pacific Northwest as well as purchased power, natural gas and coal costs. Any combination of a reduction in hydro conditions or an increase in the price of coal or natural gas could adversely impact PGE's near term earnings."[8] Bank of America Merrill Lynch writes: "We like the fundamental ratebase story of PGE, but believe it has some unique risks. Risk issues are: 1) Power cost adjustment mechanism has a wide bandwidth and 2) Sales decoupling does not offer protection from weather or industrial sales. We believe these factors cause earnings volatility and a discount valuation for PGE is warranted."[9]

Q. How would increased earnings volatility impact PGE's cost of capital?

A. Increased earnings volatility results in increased uncertainty or risk. Investors and creditors require greater compensation for owning an investment with more risk, all else being equal. A firm with greater earnings volatility will have a higher cost of capital than a firm with more stable earnings. If the current PCAM structure results in a higher level of earnings volatility relative to that faced by comparable firms, then investors' required rate of return for PGE will be higher as well. As a result, investors will demand a higher return to hold PGE's debt or stock.

Q. Is PGE seeking any changes in its PCAM to reduce perceived volatility?

A. Not at this time. We are studying the impact of the current PCAM and may suggest changes in the future.

B. Decoupling

Q. Please describe PGE's current decoupling mechanism.

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[8] J.P.Morgan. Portland General Electric Co. 2012 RFPs: Reviewing Potential Long-Term Growth Catalysts. July 10, 2012.

[9] Bank of America Merrill Lynch. Portland General Electric Company. Q2 in line, guidance affirmed; but LT growth depends on RFP.

A. PGE proposed a decoupling mechanism in the UE 197 proceeding with the intention of removing the inherent disincentives that would otherwise exist for PGE to promote energy efficiency. Decoupling applied to residential and small commercial/industrial customer rates for a two-year trial period, as specified in OPUC Order No. 09-020. The Commission believed that the designed mechanism would reduce PGE's risk and, as a result, reduced PGE's authorized ROE by 10 basis points. The potential for PGE to recover an amount greater than its fixed costs under certain circumstances was taken into account in the authorized ROE reduction as well. As the result of our last general rate case, UE 215, PGE's decoupling mechanism was extended for additional three years and will expire at the end of 2013. However, PGE is proposing to continue decoupling indefinitely.

Q. Is PGE proposing any changes to the current decoupling mechanism?

A. No, not at this time.

Q. Are decoupling mechanisms becoming more prevalent in electric utility regulation?

A. It appears that decoupling mechanisms are becoming more prevalent in the industry. A recent report (July 2012) by the Edison Foundation[10] indicated that 27 states have approved fixed cost recovery mechanisms – 14 with revenue decoupling and 13 with lost revenue adjustment mechanisms. Eight additional states had open cases that await a decision by their respective regulators.

[10] http://www.edisonfoundation.net/iee/Documents/IEE_StateRegulatoryFrame_0712.pdf.

III. Financial Markets and Economic Overview

Q. Please provide an overview of the market conditions that existed during 2011 and 2012.

A. The world economies are coming out of a very steep decline, which for some began in 2007. For some economies, like the US, the decline was a "Great Recession" – a very steep decline and then a long, slow growth path afterwards. For other economies, the Great Recession became almost a "Depression" – their economies are still declining after several years and unemployment is over 20%. For still other economies, they also experienced the Great Recession but are now on the precipice of sliding back into recession. Investors are keenly aware of how fragile the economic recovery has been world-wide and because these economies are interdependent, a significant event in any one of them will likely affect the others. Thus, investors have this significant negative overhang regarding any financial outlook. Indeed, the issues that were prevalent before 2011 are still prevalent today:

- Several countries in the Eurozone, such as Greece, Italy, Spain and Portugal, are having significant issues with their borrowing liquidity and at times seemed to approach default;
- The housing market in the US has just recently showed signs of growth but there is considerable uncertainty regarding the composition of the housing inventory and when this inventory will come on the market;
- Although the equity markets in the US have approached their levels before the Great Recession, there remains considerable uncertainty as to its strength; and
- The US federal budget deficit continues to remain at exceptionally high levels and Congress does not seem any closer to a solution, that would better align revenues,

spending and debt, creating uncertainty regarding not just interest rates but also taxes and possibly further "fiscal cliffs" in the future.

Against this background, the US economy performed somewhat sluggishly, averaging approximately 2.7% GDP growth in 2012. Job creation exceeded expectations at the beginning of the year, but slowed significantly in the second quarter before picking up somewhat in the third quarter. Housing also showed improvement during the year, but it was tepid for most of the year. In addition, government spending declined because the fiscal stimulus injections from earlier years were ending.

Q. Do other potential risks remain in the U.S. or global economies?

A. Yes. There are potential risks. The biggest risk is that the global economy will slip back into recession due to some triggering event, such as a default by one of the weaker Eurozone economies. In short, there is still significant uncertainty in the financial and capital markets.

A. Financial Regulation

Q. How have financial sector regulations changed?

A. Following the financial crisis, policymakers and regulators have sought to impose tougher rules and standards on banks in hopes of preventing future systemic crises. Regulatory efforts have been primarily focused in the following four areas: higher capital requirements (including higher minimum ratios and higher quality capital); new liquidity standards (new ratios and requirement for higher quality liquid assets); assigning higher capital requirements and increasing supervision for the largest (Systemically Important Banks); and adopting national initiatives (Dodd-Frank Act and Basel III in reference to the US).

Q. How will the banks meet these new requirements?

A. First, the banks have tightened lending standards during 2012, making it more difficult for firms to access credit, potentially increasing firms' costs to obtain access. Second, banks were forced to participate in the liquidity scenarios outlined by central banks around the world, encouraging many to keep more reserves on hand than they had historically. One additional result is that US banks have significant excess reserves at the Federal Reserve (Fed),[11] leaving less available for lending.

Q. Will these new requirements affect PGE's ability to access funds?

A. Yes. As we discussed above, PGE is potentially embarking on several major construction projects and needs ready access to both short- and long-term funds. These new requirements have tightened the availability of those funds, which would drive costs higher. PGE's request in this docket for its funding requirements would help alleviate some of this risk.

B. Liquidity Management

Q. What is PGE's strategy for liquidity management and related revolving credit facility sizing?

A. PGE's strategy is to:

- Maintain financial flexibility by carrying sufficient revolving credit levels to support both power supply and other operational needs.
- PGE's strategy is to maintain a designation of "adequate" from both rating agencies, but target a designation of "strong" or better by S&P and "good" or better by Moody's.

[11] http://libertystreeteconomics.newyorkfed.org/2012/12/why-or-why-not-keep-paying-interest-on-excess-reserves.html.

- Fund actual short-term debt requirements as efficiently as possible utilizing commercial paper or revolver loans as appropriate. Issue letters of credit in lieu of cash collateral if pricing dictates.
- Manage market exposure related to maturing lines of revolving credit by maintaining multiple facilities with varying maturity dates.

Q. Has PGE separately analyzed its revolver requirements?

A. Yes. PGE has separately analyzed its revolver requirements for Power supply versus other operational needs, the sum of which yields the total liquidity requirement for PGE's needs. The separation has allowed PGE to ensure that its power and gas procurement efforts have enough liquidity to meet collateral requirements while also maintaining sufficient liquidity for operating our electric utility business.

Q. What were the results of your analysis?

A. Based on our analysis, we determined that our revolver capacity of $700 million is currently adequate but also that we may need to increase that capacity to $800 million or more in 2013 depending on the results of the RFPs, changes in power prices, related collateral requirements, and other factors. Our results for our liquidity needs for general operations were between a low of $250 million and a high of $500 million while our power supply liquidity needs were between a low of $170 million and a high of $340 million. Our results are shown in Table 2 below.

Table 2
PGE's Liquidity Needs
($ millions)

	Low	Moderate	High
General Operations	$250	$375	$500
Power Supply	$170	$250	$340
Total Credit Required	**$420**	**$625**	**$840**

Q. How did you perform your analysis?

A. For power supply liquidity needs, we began with PGE's actual December 2012 collateral position and then decreased wholesale power prices by one and two standard deviations (i.e., 20% and 50%), assuming no changes in our current strategy for power procurement. As shown in Table 3 below, the liquidity required for power supply ranges from \$160-\$180 million at one standard deviation to \$320-\$360 million at two standard deviations.

Table 3
Power Supply Liquidity Analysis
(\$ millions)

	Collateral Range	Revolver Need
One Standard Deviation (20% Price Change)	\$160-\$180	\$170
Two Standard Deviations (50% Price Change)	\$320-\$360	\$340

For our other business needs, we considered such factors as an interruption in operational cash flow, lower earnings, temporary lack of access to capital markets, poor hydro conditions, and forced plant outages. We developed several scenarios to "stress" the liquidity requirements of general operations. Under the four scenarios, PGE would require between \$250-\$500 million of liquidity.

Q. Did you consider any other factors?

A. Yes. We also considered both one and two 'notch' downgrades by Standard & Poor's and Moody's. Such a downgrade would significantly inhibit PGE's ability to access the capital markets to support our power operation needs as well as our general operations and capital investment plans.

Q. Can you briefly summarize Moody's and Standard & Poor's liquidity methodologies?

A. Yes. Moody's has three ratings for a company's liquidity: good, adequate, or inadequate. If a company's sources of liquidity to its uses of liquidity is 200% or above, then Moody's would classify its liquidity as "good". If this ratio is 100%, then Moody's would consider the company's liquidity as "adequate". Finally, if the ratio is less than 100%, then Moody's would consider the liquidity "inadequate".

Standard & Poor's has five ratings: exceptional, strong, adequate, less than adequate, and weak. Standard & Poor's calculates the sources and uses of liquidity under normal business conditions, then "stresses" the liquidity by reducing the sources of liquidity in a specific manner through EBITDA. Since the focus is on the first three ratings, we describe only those three.

In the unstressed scenario, if the company has a minimum ratio of 2x (sources of funds to uses of funds) and its sources of funds is still positive after a 50% decline in EBITDA, then Standard and Poor's rates the company "exceptional." In the unstressed scenario, if the company has a minimum ratio of 1.5x and its sources of funds is still positive after a 30% decline in EBITDA, then Standard & Poor's rates the company "strong." Finally, to be "adequate," in the unstressed scenario, the company must have a minimum ratio of 1.2x and its sources of funds must be positive after a15% decline in EBITDA.

Q. What were the results of your analysis?

A. For Moody's criteria, our analysis found that our liquidity profile would be rated "adequate" in 2014, but just barely. For Standard & Poor's, we would also be rated "adequate", but just barely. Based on this set of analyses, we determined that our current revolver capacity of $700 million is adequate but also that we may need to increase that capacity to $800 million in 2013 depending on the results of the RFPs, changes in power prices, related collateral requirements, and other factors.

C. Broker Fees

Q. Please describe broker fees.

A. Broker fees are a direct result of PGE's participation in the wholesale power markets. The power markets have evolved over time from bilateral trades between and among electric utilities (a predominantly physical market without independent parties) to one that now incorporates many independent parties and is predominantly financial. While this evolution has brought benefits such as more counterparties and additional liquidity, it has also brought with it more explicit fees. Rather than transacting just once with a physical deal and incurring one fee, a financial deal requires two transactions and typically three fees. In the first transaction, PGE enters into the financial arrangement (e.g., "fixed" or "floating" swap) where PGE typically incurs an over-the-counter (OTC) broker fee and a clearing broker fee. In the second transaction, which typically occurs closer to the execution date, PGE enters into a physical transaction (e.g., an index purchase) and incurs just an OTC broker fee.

The amount of fees PGE incurs in a given year is also subject to market conditions that affect the volume of transactions PGE enters into. Factors that come into play include available generation, loads, market liquidity, and hydro conditions.

Q. How has PGE forecasted broker fees for 2014?

A. PGE has forecast 2014 broker fees using historical actuals from 2012 as a basis and escalating at approximately 3.1%, the estimated CPI provided by Global Insight, for expected increases in fee rates. Broker fees for the 2014 test year are estimated to be about $0.5 million.

IV. Cost of Long-Term Debt

Q. How did you calculate the cost of long-term debt for 2014?

A. PGE Exhibit 1101 shows the amount and the effective cost of PGE's outstanding long-term debt for the test year. This includes existing bond issuances as of December 31, 2012, as well as bond issuances and retirements expected in 2013 and 2014. We included the applicable adjustments to debt as approved in OPUC Order No. 07-015 when calculating the amount of debt outstanding. The full amount and cost for each issuance of debt outstanding at year end is included. We then multiply the amount outstanding by the effective interest rate for each bond issuance. The effective interest rate represents the internal rate of return for each of the cash flows associated with each debt issuance, including all unamortized call premiums and issuance expenses for debt issuances replaced before maturity with less expensive financings. PGE's annual cost of long-term debt for the 2014 test year has decreased from that occurred in 2011 by more than 61 basis points, a significant decline. Table 4 below summarizes PGE's cost of long-term debt for 2014.

Table 4
PGE's Cost of Long-Term Debt ($000)

	2014 Forecast	2011 Actual	Difference
Principal Amount	$ 2,091,400	$ 1,735,000	$ 356,400
Annual Interest Cost	$ 119,754	$ 110,000	$ 9,754
Effective Interest Rate	**5.726%**	**6.340%**	**-0.614%**

Q. What future debt issuances did you include in your analysis?

A. We expect to issue $400 million in long-term fixed rate debt during the remainder of 2013. We also expect to issue an additional $225 million of long-term debt in 2014.

Q. What is the expected term, coupon rate, and issuance cost for the bonds to be issued in 2013 and 2014?

A. PGE currently expects to issue two First Mortgage Bonds (FMBs) in 2013 that will each carry a coupon rate of 4.57% for a term of 30 years. The $225 million FMB scheduled for 2014 is expected to carry a coupon of 5.15%, also for a term of 30 years. We will update our cost of debt when new information becomes available.

Q. How were the expected coupon rates and issuance costs derived by PGE?

A. The rates and issuance costs are based on an indicative new issuance pricing analysis, which includes a current estimated credit spread provided by a bank and a forecast of treasury rates from Global Insight.

Q. Is any long-term debt maturing in 2013 or 2014?

A. Yes. Two issuances are maturing in 2013, representing $100 million. One is a FMB issued in 2003 for $50 million and another is a FMB issuance of 2008 also for $50 million. There are no long-term debt issuances maturing in 2014.

Q. Has PGE issued or redeemed any long-term debt since PGE filed UE 215 in 2010?

A. Yes. In UE 215, PGE expected to remarket two pollution control bond (PCB) issuances representing $23.6 million and $97.8 million for the remainder of their 23-year terms with coupon rates of 5.0% and 5.1%. Both PCB issuances were remarketed at 5%. A $59 million bond issuance was assumed and was expected to carry a coupon rate of approximately 4% for a term of 7 years. Instead, PGE issued $58 million with 3.81% coupon in June 2010. PGE also reacquired $9.6 million of Trojan 90A PCBs in January 2011 and $63 million in 6.5% series of FMB in December 2011. Both of these issuances were retired. These debt issuances and redemptions are detailed in PGE Exhibit 1101.

Q. Since UE 215, what impacts have PGE's overall financing activities had on customers?

A. At the 2014 outstanding effective interest rate, PGE will incur $7.3 million less in interest and related charges than if the same debt balance was financed at the UE 215 effective interest rate.

V. Capital Structure

Q. How did you determine the appropriate capital structure for 2014?

A. We evaluated PGE's capital structure using the forecasted income statement and balance sheet for 2014, as well as our expected financings through 2014. Additionally, we considered several factors, including PGE's need to maintain its financial strength, flexibility and adequate liquidity; its ability to maintain reliable and economical access to the capital markets; minimizing the cost of capital to customers and shareholders; and the Commission's Orders in UE 215 (Order No. 10-478), UE 197 (Order No. 09-020), and UE 180 (Order No. 07-015).

Q. Does PGE expect to issue equity in 2014?

A. PGE's decision to issue common equity in 2014 will be dependent upon the results of the RFP processes and corresponding capital expenditures. As mentioned above, we prepared this filing under the assumption that PGE will have significant capital additions resulting from the ongoing RFP processes. These capital additions would result in PGE issuing approximately $375 million in equity. As we learn the results of the bidding process (sometime in the first half of 2013), we will update our financing needs accordingly.

Q. Are you seeking a different capital structure than that in UE 215?

A. No. In UE 215, Order No. 10-478 reaffirmed PGE's regulated capital structure at 50% equity and 50% debt. PGE's long-term goal continues to be to maintain our capital structure at 50% equity and 50% debt; however, the equity ratio does fluctuate around the 50% target level, due to the timing and size of debt and equity issuances. PGE expects the level of regulated equity to exceed 50% by the end of the test year and during 2015 to accommodate the RFP results.

Q. Why does PGE intend to maintain 50% equity, 50% debt capital structure?

A. The equity portion of PGE's capital structure is important because it represents how PGE finances its cash needs. In addition, the equity portion helps offset the leverage and risk that PGE will encounter, in part, as it continues to implement a large capital expenditure program over the next few years. It is also required to help offset the leverage imputed by the rating agencies due to PGE's above-average reliance on purchased power, discussed in more detail below. In light of ASC 810 (discussed below), understanding and mitigating the leverage created by imputed debt is all that more important. Additionally, as we discuss below, PGE faces many risks in today's banking environment, and it must be able to maintain a solid capital structure and financial flexibility to help contain customer costs and retain shareholder value. PGE's ability to access capital markets as an investor-owned entity is a low cost way to meet customers' needs.

Q. Has the Commission noted any specific risks facing PGE?

A. Yes. In UE 180, Order No. 07-015, the Commission noted that PGE has significant exposure to the wholesale market, especially when compared with PacifiCorp. In particular, PGE faces risk related to the volatility of wholesale electricity prices. Volatility in these markets can affect the availability and the prices of purchased power and demand for energy sales. This volatility can result in the deterioration of market liquidity, increase counterparty credit risk, and impair PGE's ability to manage its energy portfolio. While PGE's PCAM mitigates this risk to some degree, it does not provide full recovery of all costs outside the cost sharing features. The Commission reaffirmed in Order No. 10-478 that the PCAM's application should be limited to unusual events and capture power cost variances that exceed those considered normal business risk. In Order No. 07-015, the Commission found that an additional 10 basis points on ROE was appropriate to balance PGE's risk exposure in the area of wholesale prices.

Q. Aside from the risks discussed above, what other types of risks does PGE encounter today?

A. PGE faces several significant risks and uncertainties, including:

- Imputed debt from purchased power contracts: As we noted above, S&P "imputes" additional debt to PGE's capital structure based on the capacity payment of existing PPAs. S&P believes that capacity payments are quasi-debt instruments and an adjustment must be made to the capital structure to reflect the additional leverage of PPA contracts. PGE's imputed debt ratio could increase above 55% by 2014 if all RFPs are served by PPAs. Significant increases in the debt ratio are a quantitative trigger for potential ratings downgrades. A ratings downgrade by S&P from PGE's current BBB rating could result in higher interest rates on debt issuances, an inability to attract equity capital at a reasonable price, and additional collateral postings for power supply operations. We estimate the additional collateral posting amount to be at $250 million[12] as of December 31, 2012 based on our current contracts.
- Accounting Standards Codification 810 (ASC 810) Consolidation of Variable Interest Entities (VIE): ASC 810, Consolidation, provides guidance for determining the financial reporting for entities over which control is attained by means other than through voting rights. Under ASC 810, consolidation is based on the power to direct significant activities of the VIE and the obligation to absorb losses that are significant to the VIE. The entity with the power to direct significant activities and the

[12] PGE 2012 SEC Form 10K report, page 63.

obligation to absorb significant losses becomes the "primary beneficiary" of the VIE and, in turn, is required to consolidate the financial statement of the VIE for financial reporting to the SEC. ASC 810 requires consolidated financial statements to reflect total assets under control and total liabilities for which an entity is responsible.

Under ASC 810, PGE may be required to reflect the total assets, liabilities and non-controlling interests of its PPA counterparties on PGE's balance sheet on an ongoing basis when reporting its financial position on a consolidated basis. Although PGE is not involved in the creation of these entities and has no equity or debt invested, PGE may be required to consolidate their financial results with that of PGE. The counterparty entities are expected to be highly debt-leveraged and consolidating their capital structure will likely distort PGE's authorized capital structure. High debt leverage will impact PGE's creditworthiness, as the increase to PGE's debt-to-equity percentage increases financial risk. To support PGE's creditworthiness and realign its capital structure, an increase to PGE's common equity could be necessary to offset the impact of the additional debt, consolidated under ASC 810.

- Hydro and wind availability and weather changes: Weather creates risk for PGE in several ways, including: lower than average stream flows; lower than average wind flows; and volatility in electricity usage because of sudden, unexpected, weather changes. This weather risk is not mitigated by our decoupling mechanism. These risks can potentially force PGE to purchase more spot energy, when the markets may be tight. The higher costs resulting from these purchases combined with the volatility of weather conditions can increase costs to PGE and its investors, requiring a higher return than otherwise.

- Regional economic weakness: Regional economic weakness can adversely affect PGE's revenues. Weakness in the state of Oregon, can lead to a decline in electricity usage as customers become more conservative. This can negatively impact PGE's revenues, thereby reducing PGE's profits, which negatively affect PGE's retained earnings and returns to investors. Lower retained earnings affect our ability to reinvest in the business. Oregon's economy was especially hard-hit during the recession and financial crisis of 2008 and did not completely recover since then. The preliminary estimate for the state of Oregon unemployment rate in December 2012 was 8.4%, 0.6% higher than the US unemployment rate.
- Renewable Portfolio Standard (RPS) compliance: Oregon's RPS requires that PGE serve at least 25% of its retail load from renewable resources by the year 2025, with interim requirements in years 2011, 2015 and 2020. PGE faces the risk that lower cost renewables will be acquired by other utilities or will be unavailable in a timely manner. In addition, PGE will incur other potential risks when placing these resources into rate base, including regulatory risk, transmission congestion, resource availability, etc. PGE faces further potential risks when seeking to efficiently integrate certain of these renewable resources into its energy portfolio.
- Uncertainty regarding possible adverse Trojan decision: Although less likely given the recent decision by the Oregon Court of Appeals, there is still some uncertainty in the financial markets regarding the ultimate outcome of the legal proceedings related to PGE's recovery of its investment in the Trojan Nuclear Plant. The uncertainties associated with Trojan, including the difficulty of quantifying the potential exposure

and estimating the timing of a final outcome, are viewed as weaknesses by the financial community.

- Uncertain federal energy policy: The federal government's potential policies regarding renewable energy mandates and the potential for restrictions on carbon emissions remain unclear. The ultimate form of any policy, and the impacts on regulated utilities, cannot be known at this point.

Q. Do the financial markets agree that these are risks for PGE?

A. Yes. Recent reports from Standard & Poor's, Moody's, and various equity analysts include at least one of the risks listed above.

Q. Can PGE manage these risks?

A. PGE can manage some of these risks, but others it cannot. Risks PGE cannot manage include those associated with the government or regulatory framework. For many risks, even though PGE can partially manage them, PGE remains significantly exposed.

Q. Could the risks addressed above alter the cost of capital you request?

A. Yes. If these risks are not mitigated to the point that PGE is comparable to its peers, the cost of long-term debt and the cost of equity will increase, with a resulting long-term cost impact on customers.

VI. Qualifications

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

A. I received a Bachelor of Science degree in Economics from Santa Clara University in 1975 and a Master of Arts degree in Economics from the University of California at Davis in 1978. In 1995, I passed the examination for the Certified Rate of Return Analyst (CRRA). In 2000, I obtained the Chartered Financial Analyst (CFA) designation.

I have taught several introductory and intermediate classes in economics at the University of California at Davis and at California State University Sacramento. In addition, I taught intermediate finance classes at Portland State University. Between 1996 and 2004, I served on the Board of Directors for the Society of Utility and Regulatory Financial Analysts. Locally, I have been on the Board of Directors for Advantis Credit Union since 2007, serving previously on the Audit Committee.

I have been employed at PGE since 1984, beginning as a business analyst. I have worked in a variety of positions at PGE since 1984, including power supply. My current position is Manager, Regulatory Affairs.

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

A. I received a Bachelor of Science degree in Business Administration from the University of Montana in 1979. I received a Master in Business Administration from the University of Oregon in 1986 with an emphasis in Finance. I joined PGE in 1991 as a Business Analyst and was Manager of Corporate Finance and Assistant Treasurer from July 1997 to September 2005 and from August 1, 2009 to February 4, 2010. Since fall of 2005, I have also held the title of Director of Investor Relations.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
1101	Cost of Long-Term Debt
1102	Standard & Poor's and Moody's Investors Service Credit Ratings

Cost of Long-Term Debt

Expected December 31, 2014 - 2014 Test Year

Updated 01.07.2013

(A)	AWO (B)	Type (C)	Description (D)	Issue Date (E)	Maturity Date (F)	Term (G)	Coupon (H)	Gross Proceeds (I)	DD&E Issue Costs (J)	Call Premium & Unamort. DD&E of Refunded Issue (K)	F/N	Net Proceeds (L) [I - J - K]	Embedded Cost (M)	Netto Gross Rate (N) [L / I]	Face Amount Outstanding (O)	Net Outstanding (P) [N * O]	Face Amount Weight (Q) [O / Total]	Weighted Rate (R) [Q * M]
1	7000000037	Series MTN	9.310% Series	12-Aug-91	11-Aug-21	30	9.310%	$20,000,000	$176,577	$0		$19,823,423	9.399%	99.117%	$20,000,000	$19,823,423	0.956%	0.090%
4	7000000021	Series VI MTN	5.625% Series	4-Aug-03	1-Aug-13	10	0.000%	$50,000,000	$0	$0	2	$0	0.000%	0.000%	$0	$0	0.000%	0.000%
5	7000000022	Series VI MTN	6.750% Series	4-Aug-03	1-Aug-23	20	6.523%	$50,000,000	$521,342	$1,946,809	2	$47,531,849	6.985%	95.064%	$50,000,000	$47,531,849	2.391%	0.167%
6	7000000023	Series VI MTN	6.875% Series	4-Aug-03	1-Aug-33	30	6.648%	$50,000,000	$521,342	$1,946,809	2	$47,531,849	7.046%	95.064%	$50,000,000	$47,531,849	2.391%	0.168%
7	7000000024	FMB	6.310% Series	26-May-06	1-May-36	30	6.310%	$175,000,000	$1,270,865	$6,199,472	3	$167,529,663	6.640%	95.731%	$175,000,000	$167,529,663	8.368%	0.556%
8	7000000025	FMB	6.260% Series	26-May-06	1-May-31	25	6.260%	$100,000,000	$723,857	$4,132,982	3	$95,143,161	6.662%	95.143%	$100,000,000	$95,143,161	4.781%	0.319%
9	7000000433	FMB	5.800% Series	16-May-07	1-Jun-39	32	5.800%	$170,000,000	$1,447,420	$50,969	4	$168,501,611	5.861%	99.119%	$170,000,000	$168,501,611	8.129%	0.476%
10	7000000027	FMB	5.810% Series	19-Sep-07	1-Oct-37	30	5.810%	$130,000,000	$1,627,092	$0		$128,372,908	5.899%	98.748%	$130,000,000	$128,372,908	6.216%	0.367%
11	7000000266	FMB	5.800% Series	12-Dec-07	1-Mar-18	10	5.800%	$75,000,000	$637,500	$0		$74,362,500	5.912%	99.150%	$75,000,000	$74,362,500	3.586%	0.212%
12	7000000267	FMB	4.450% Series	15-Apr-08	1-Apr-13	5	0.000%	$50,000,000	$0	$0	5	$0	0.000%	0.000%	$0	$0	0.000%	0.000%
14	7000000693	FMB	6.800% Series	15-Jan-09	15-Jan-16	7	6.800%	$67,000,000	$438,180	$0		$66,561,820	6.919%	99.346%	$67,000,000	$66,561,820	3.204%	0.222%
15	7000000181	FMB	6.100% Series	13-Apr-09	15-Apr-19	10	6.100%	$300,000,000	$2,608,223	$0	6	$297,391,777	6.218%	99.131%	$300,000,000	$297,391,777	14.344%	0.892%
16	7000000182	FMB	5.430% Series	3-Nov-09	3-May-40	30.5	5.430%	$150,000,000	$1,034,283	$0		$148,965,717	5.477%	99.310%	$150,000,000	$148,965,717	7.172%	0.393%
17	7000010695	FMB	3.460% Series	15-Jan-10	15-Jan-15	5	3.460%	$70,000,000	$0	$0	7	$70,000,000	3.609%	0.000%	$0	$0	0.000%	0.000%
18	7000000185	PCB	Clstrp 98A Fixed	11-Mar-10	1-May-33	23	5.000%	$97,800,000	$688,885	$1,521,911	8	$95,589,204	5.168%	97.739%	$97,800,000	$95,589,204	4.676%	0.242%
19	7000000036	PCB	Brdmn 98A Fixed	11-Mar-10	1-May-33	23	5.000%	$23,600,000	$166,234	$912,065	8	$22,521,701	5.346%	95.431%	$23,600,000	$22,521,701	1.128%	0.060%
20	7000001028	FMB	3.810% Series	15-Jun-10	15-Jun-17	7	3.810%	$58,000,000	$351,307	$0		$57,648,693	3.910%	99.394%	$58,000,000	$57,648,693	2.773%	0.108%
21	2013-1	FMB	2023 Forecast	1-Jun-13	1-Jun-23	30	4.570%	$200,000,000	$1,950,000	$0	10	$198,050,000	4.630%	99.025%	$200,000,000	$198,050,000	9.563%	0.443%
22	2013-2	FMB	2043 Forecast	1-Oct-13	1-Oct-43	30	4.570%	$200,000,000	$1,950,000	$0	10	$198,050,000	4.630%	99.025%	$200,000,000	$198,050,000	9.563%	0.443%
23	2014-1	FMB	2044 Forecast	1-Apr-14	1-Apr-44	30	5.150%	$225,000,000	$2,193,750	$0	10	$222,806,250	5.215%	99.025%	$225,000,000	$222,806,250	10.758%	0.561%
			Annual expense from loss on reacquired debt							$167,007		($167,007)						
			Totals					$2,261,400,000	$18,306,857	$16,878,024		$2,126,215,119			$2,091,400,000	$2,056,382,126	100.00%	5.718%
			Cost of LT Debt (includes annual expense from loss on reacquired debt)															5.726%

Losses on Other Reacquired Debt	Issue Date	Mat. Date	Reacquisition Date	Gross Proceeds	Total Gain/Loss to Amortize	2014 Expense	
700000C 5.450% Colstrip 98B Fixed PCB due	1-May-03	1-May-33	1-May-09	$21,000,000	$411,622	$17,139	
700000C Trojan 90A Fixed	1-Jul-98	1-Aug-14	15-Jan-11	$9,600,000	$63,836	$10,459	1
700000C 6.500% Series	15-Jan-09	15-Jan-14	29-Dec-11	$63,000,000	$7,448,429	$139,409	9
						$167,007	

Footnote

1 On 7/1/98, the Trojan variable rates were fixed, although not extended. These bonds were redeemed at par in January 2011. Includes partial-year 2014 amortization of reacquisition cost.

2 $5.8 million in call premia resulting from acquisition of 9.46% and 7.75% issues was allocated evenly among August 2003 issues (see UE 180, PGE Exhibit 1400, page 3). 5.625% Series moves to due w/in one-year in August 2012.

3 There was a $12 million call premium on the 8.125% redeemed issue. A portion was disallowed in UE 180. The remainder is rolled into the new debt and will be paid over the period of the May 2006 issuances.

4 $5.1 million Trojan 1990B PCBs redeemed early in June 2007. Unamortized loss of $50,969 was added to the 5.80% series $170MM issued in May 2007 used to redeem the PCBs.

5 In February 2008, PGE repurchased the 5.279% issue due 04/01/2013. The issue was subsequentally reissued on 04/15/2008 at 4.45% for a period of 5 years (due on original maturity date of 04/01/2013). Moves to due w/in one-year in April 2012.

6 "DD&E Issue Costs" (column J) was updated to reflect $222,000 discount to par at issuance.

7 "DD&E Issue Costs" (column J) was updated to reflect actual issuance expenses.

8 PCB issues put-back to PGE in May 2009. PGE re-marketed in March 2010 (due on original maturity date of 05/01/2033).

9 The 6.500% Series was redeemed on December 29, 2011. The make-whole payment was $7,279,650. Includes partial-year 2014 amortization of reacquisition cost.

Standard & Poor's and Moody's Investors Service Credit Ratings

	S&P	Rating Date	Moody's	Rating Date
Senior Secured Debt	A-	2/21/2012	A3	7/2/2012
Senior Unsecured	BBB	2/21/2012	Baa2	7/2/2012
Short-term/ Commercial Paper	A-2	2/21/2012	P-2	7/2/2012

"Credit Opinion: Portland General Electric Company" February 21, 2012. Standard & Poor's
"Credit Opinion: Portland General Electric Company" July 2, 2012. Moody's Investors Service

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 262

Return on Equity

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Thomas M. Zepp

February 15, 2013

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I. Introduction and Summary

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

A. My name is Thomas M. Zepp. I am an economist and vice president of Utility Resources, Inc. My office is located at Suite 250, 1500 Liberty Street, S.E., Salem, Oregon 97302.

Q. What is the subject of your testimony in this proceeding?

A. Portland General Electric Company (PGE or the Company) asked me to estimate its required return on equity (RROE or ROE). I also call the RROE the "cost of equity" in this testimony. My study is based on data available to investors in December 2012.

Q. What are the results of your analysis?

A. The results of my analysis are provided in Table 1 below:

Table 1

Basis for Estimate	Estimated Cost of Equity for a Benchmark Sample of Electric Utilities
First Discounted Cash Flow ("DCF") Analysis	10.1%
Second DCF Analysis	10.1%
Third DCF Analysis	10.3%
First Risk Premium ("RP") Analysis	10.0% to 11.1%
Second RP Analysis	10.5% to 11.1%
Third RP Analysis	10.3%
Range of Earned, Forecasted and Authorized ROEs	10.2% to 10.6%
Estimated Range of Benchmark Costs of Equity	10.0% to 10.7%

PGE is more risky than the benchmark sample used to make these cost of equity estimates and thus it is appropriate to authorize an ROE for PGE that is above the mid-point of the estimated benchmark cost of equity range of 10.0% to 10.7%. PGE's requested return on equity ("ROE") of 10.0% is thus a very conservative estimate of its cost of equity and is reasonable.

Q. Please discuss current economic activity and other factors that put your cost of equity estimates in perspective.

A. During the last few months there have been some indications the U. S. economy is on the mend after the most severe recession in memory. But, investor concerns about the risks of equity investments continue for a number of reasons. The national jobless rate remains stubbornly high at 7.9% and there has been mediocre growth in GDP, which does not appear to be sustainable in the near term due in part to the devastation caused by Hurricane Sandy on the East Coast. (Value Line, Selection & Opinion, November 16, 2012). This news comes on the heels of several months of concerns with the outlook for the Euro Zone and slower than historic annual growth in China. Also, as of the writing of this testimony, though Congress reached a contentious agreement that avoided the worst impacts of automatic tax increases and spending cuts that would have resulted from not addressing the "fiscal cliff," investors are well-aware that the looming national debt ceiling must still be addressed. Most analysts expect Congress and the President will reach some type of temporary accord but that Congress will likely "kick the can" down the road and not reach a permanent solution to the high deficits in our country. There is obvious risk the unknown permanent solution which may change taxes, spending and the debt ceiling—if one is reached—will be unfavorable to equity investors.

In August of 2011, S&P took the unprecedented step of down-grading Treasury securities of the United States from AAA to AA+. But as a result of the continuing uncertainty and risk, investors are still pricing Treasury securities at relatively high levels—even after the downgrading by S&P—and thus accepting lower yields than are available on "lower risk" AAA corporate bonds. When investors drive down the bond yield by paying higher prices for bonds, this indicates that investors perceive considerable risk in the equity markets. It is this perception of risk that impacts the cost of equity capital pushing it higher. Under these circumstances, those investors willing to invest in equities require higher returns to compensate them for the perceived higher risk. As a result, there are a number of factors which suggest the costs of equity for utilities continue to be high.

Another factor is interest rates have dropped to historically low levels when compared to interest rates for similar securities in the past (see PGE Exhibit 1202). For example, from 1980 to 2002, annual average rates for 30-Year Treasury bonds ranged from 5.43% to 13.45%. In 2009, that annual average dropped to 4.08% during the recession, dropped further in 2011 to 3.91% and dropped below 3.0% in 2012. The exceptionally low bond rates in 2012 are the result of prevailing economic conditions, continuing problems in the Euro Zone, as well as "quantitative easing" of the Federal Reserve. Notwithstanding these current low rates and easing promised by the Federal Reserve, some analysts are concerned that the Federal Reserve's quantitative easing cannot continue indefinitely without consequences in financial markets. The consensus of analysts' forecasts indicates interest rates are expected to bounce back up in 2014–2015. Averages of analysts' forecasts of rates for long-term Treasury securities, Aaa rates and Baa rates for this period are 4.19%, 4.94% and 5.76%, respectively.

Q. Are you aware of quantitative evidence which shows equity risk premiums are higher today than in the past?

A. Yes. There are theoretical reasons why equity risk premiums (ERPs) are expected to increase as interest rates decrease, which I discuss in Section IV below. I am also aware of two quantitative studies which found ERPs are much higher today than in the past. The first is an analysis I prepared using data estimated by Value Line for its Industrial Composite. The second is a February 2012 study reported by Bank of America Merrill Lynch.

Q. Why is the evidence important?

A. It is important because it shows costs of equity have not dropped nearly as much as the decrease in interest rates. Both studies show equity risk premiums are higher today than the average ERP in the past. Based on this evidence, the Commission should anticipate that the costs of equity for PGE and other utilities—revealed in DCF models and other financial models—have not have dropped very much in recent years.

Q. Please discuss your study of the equity risk premium required by the Value Line Industrial Composite.

A. Value Line prepares estimates of the financial characteristics of its "Industrial Composite" (IC) once or twice a year. The IC currently consists of 911 industrial, retail, and transportation companies, which comprise 82 of Value Line's 100 industry groups. Financial data and stock market values for these companies have been pooled as if they belong to one large corporation. Given the breadth of the industry groups considered in the IC analyses, I anticipate the ERP for this group of companies will provide a useful indicator of the ERP required by an average risk stock. PGE Exhibit 1203 reports my study. I performed the 41 DCF analyses reported in PGE Exhibit 1203 using data determined by

Value Line for the IC during the period 1984 to 2012. To compute growth rates, I averaged Value Line's forecasts of earnings per share (EPS) growth and expected future growth from retained earnings from each of those Value Line studies. Over the entire period, the average indicated equity risk premium in excess of long-term Treasury bond rates was 6.5%. During the last four years, however, the indicated average expected equity risk premium was 8.6%. This estimate of 8.6% indicates investors currently require a higher ERP in response to lower interest rates and concerns with making equity investments at this time.

Q. Please discuss the study reported by Bank of America Merrill Lynch.

A. Bank of America Merrill Lynch published this study in February 2012. They report that their Dividend Discount Model (a DCF model) indicates the equity risk premium is currently more than 800 basis points above the Corporate AAA bond rate, the highest in the history of its data and nearly double the 30-year average of 418 basis points. Bank of America Merrill Lynch says it sees reasons for structurally higher risk premiums over the next several years. Volatility of the full-cycle of earnings growth is now at a 70-year high and equities should incorporate a higher equity risk premium to compensate for this unprecedented level of earnings risk.

Q. What do these studies indicate about changes in the cost of equity that have occurred in the last few years?

A. Both studies indicate that the decreases in costs of equity associated with lower interest rates have been largely offset by increases in required ERPs. The increases in required ERPs have occurred in part because ERPs are expected to increase as interest rates decrease. But, at the present time, ERPs have also increased due to current negative factors in the U.S. and other world markets. The Commission should expect reasonable applications of the DCF and RP financial models for electric utilities will also show costs of equity for those utilities have not dropped very much in recent years.

Q. How is your testimony organized?

A. In this section, I present the concept of a fair rate of return and a summary of my analysis.

In Section II, I compare the risks of the electric utilities sample I rely upon to determine benchmark DCF cost of equity estimates to risks faced by PGE. The Commission has previously determined PGE has above-average risk from its significant exposure to the wholesale market and below-average risk from decoupling which is available to most, but not all, utilities in the benchmark sample. Mr. Hager and Mr. Valach point out a number of factors that indicate PGE is expected to continue to be more risky in the future. I present quantitative evidence in this section which shows the net impact of these factors increases PGE's cost of equity and RROE. PGE has a higher beta, is smaller, and has higher relative risk than the average utility in the sample I use to determine benchmark cost of equity estimates.

Section III develops my DCF equity cost estimates for a benchmark sample of 20 small electric utilities (including PGE) based on three alternative DCF approaches.

Section IV presents three RP analyses. Initially I explain why it is reasonable to expect equity cost risk premiums to vary inversely with interest rates and present different types of evidence that support such a conclusion. Subsequently, I present equity cost estimates based on three different RP approaches.

In Section V, I present a check on the reasonableness of my DCF and RP equity cost estimates based upon Value Line forecasts of ROEs, authorized ROEs and earned ROEs for the benchmark sample of 20 utilities.

Section VI provides a summary of my analysis, an estimated range in which the cost of equity falls, and my conclusion that PGE has a cost of equity that falls in the upper half of my range of estimated costs of equity for the sample. Based on my analysis, PGE's requested ROE of 10% is conservative and reasonable.

Q. Have you prepared any exhibits to accompany your testimony?

A. Yes. I have prepared 16 exhibits that support my testimony.

Q. Please discuss what is meant by a fair rate of return.

A. A fair rate of return is achieved when a utility is authorized rates and rate adjustment mechanisms at levels where the expected return provides common stock investors a reasonable opportunity to earn the cost of common equity. Because operating expenses and interest on debt take precedence over payments to common stock holders, it is the common equity shareholder of the company who bears the greatest risk of receiving expected returns. In 1923, the U.S. Supreme Court set forth the following standards in the Bluefield Waterworks decision:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economic management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally. 262 U.S. 679, 692-93 (1923).

In the Hope Natural Gas Company decision, issued in 1944, the U. S. Supreme Court stated the following regarding the return to owners of a company:

> [T]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. 320 U.S. 591, 603.

In 1989, in Duquesne Light Co. v Barasch the U.S. Supreme Court also recognized an important economic concept, it found that regulatory commissions may need to adjust the risk premium element of the rate of return on equity to provide a fair return. It said:

> [W]hether a particular rate is "unjust" or "unreasonable" will depend to some extent on what is a fair rate of return given the risks under a particular rate setting system . . . .488 U.S. 299, 310.

Therefore, in determining an appropriate return, consideration must be given to the specific risks created by the nature and degree of regulation to which the utility is subject, in addition to examining general economic and financial data for utilities.

In Oregon, the legislature passed ORS 756.040, which puts into state law the principles the U.S. Supreme Court established in the Hope and Bluefield decisions.

Additional risk faced by PGE should be recognized when setting the fair rate of return for the Company. In Orders No. 07-015 and No. 09-020, the Commission recognized PGE's RROE may need to differ from returns for other utilities due to higher or lower risks. I estimate the net impact of risks identified by the Commission together with other risks discussed by Mr. Valach, Mr. Hager, and me indicate PGE's RROE is higher than the average ROE required by the utilities in the benchmark sample I rely upon to conduct my ROE analyses.

Q. What is the crucial implication of the principles set out by the U. S. Supreme Court and in ORS 756.040 in the determination of a fair rate of return for PGE?

A. The crucial implication is that the rates and rate adjustment mechanisms authorized for PGE by the Oregon PUC should give PGE an opportunity to earn the rate of return investors could expect to earn if they invested in another utility of comparable risk. That rate of return should be sufficient to attract capital on reasonable terms and high enough to assure confidence in the financial integrity of PGE. As I discuss further below, PGE is more risky than the electric utilities samples I rely upon to determine benchmark estimates of the cost of equity and thus its RROE is higher.

Q. Are there other implications?

A. Yes. Other implications differ among bondholders and customers of PGE. From the perspective of bondholders, authorized rates need to be sufficient to assure current and prospective bondholders that PGE will have interest coverage comparable to other utilities having similar risk. Otherwise, the acceptance of PGE's bonds will decline and borrowing costs will increase. An increase in bond costs ultimately falls on the shoulders of PGE's customers. Access to competitively priced capital is especially important at this time when PGE anticipates it will need to issue bonds and equity to fund large new capital expenditures.

From the perspective of customers, the RROE is another cost of service required by PGE so it can provide safe, reliable and adequate service now and in the future. Thus, the rates customers pay should provide a reasonable opportunity for PGE to earn that cost of equity. The fair rate of return on common equity is the cost of common equity and PGE's RROE.

Q. Please summarize your testimony.

A. My findings and recommendations are the following:

1. The cost of common equity faced by PGE is greater than the cost of common equity that faces a typical electric utility:

- It has above-average risk from its significant exposure to the wholesale market.
- It has higher risk due to its above-average percentage of purchased power.
- It is more risky than other utilities in the DCF sample based on two tests of relative risk discussed in Section II.
- It is more risky because it is smaller than a typical electric utility.
- It has higher market risk as measured by beta than the average utility adopted to make DCF cost of equity estimates.

2. PGE may be less risky due to decoupling, however, risks of energy conservation efforts which drive the need for decoupling appear to offset those benefits. A recent Brattle Group study presents statistical estimates that support that conclusion. Also, any benefits of decoupling are largely in my DCF cost of equity estimates because most of the utilities in the sample used to make benchmark cost of equity estimates have some form of decoupling.

3. The benchmark cost of common equity for the electric utilities samples I use to determine guideline equity costs falls in a range of 10.0% to 10.7%:

- Three DCF estimates for the electric utilities sample indicate the cost of equity falls in a range of 10.1% to 10.3%;
- Costs of equity derived from three risk premium analyses indicate the cost of equity for the benchmark electric utility sample falls in the range of 10.0% to 11.1%; and

- Averages of earned ROEs for the sample of 10.2%, Value Line forecasts of future ROEs of 10.6% and authorized ROEs of 10.4% corroborate the reasonableness of these RP and DCF equity cost estimates.

4. I conclude that PGE's RROE falls above the mid-point of the range of 10.0% to 10.7% estimated for the sample and conclude the Company's requested ROE of 10.0% is reasonable and should be authorized (see PGE Exhibit 1216).

II. Risks of PGE and the Electric Utilities Sample

Q. As a preliminary matter, please discuss the sample of electric utilities you used in your DCF analyses.

A. I have used the sample of 20 electric utilities listed in the two-page PGE Exhibit 1201 to determine my benchmark DCF cost of equity estimates. AUS Utility Reports provides information for 53 utilities it includes in categories it calls "Electric Companies" and "Combination Electric & Gas Companies." My electric utilities sample is composed of the smallest 20 companies in these AUS Utility Reports categories that paid, but did not cut, dividends during the last five years, are not being acquired, were vertically integrated companies, have at least 50% of their regulated revenues coming from electric operations and had an investment grade bond rating. PGE Exhibit 1201 lists percentages of revenues from electric operations, Value Line estimates of betas, expected common equity ratios, Standard & Poor's business risk and financial risk profiles, bond ratings, information showing whether the utilities have decoupling or other fixed cost recovery mechanisms, size of the utilities, and percentages of purchased power. It also displays averages of that information for the sample and comparable data for PGE. This sample of 20 utilities provides a reasonable basis to estimate benchmark costs of equity. To the extent the data permit, I have relied on this full sample of 20 electric utilities to determine my benchmark DCF cost of equity estimates.

Q. Please provide an overview of your discussion of risk.

A. Investors can choose to invest in many different types of assets with varying degrees of risk. Those investments might be in real estate, gold, collections of fine art, or financial assets. The financial assets run the gamut from relatively low risk assets, such as Treasury securities and somewhat higher risk investment grade corporate bonds, to relatively high-risk shares of common stocks. As the level of risk increases, investors require higher expected returns. Common stocks of utilities are generally more risky and thus require higher returns than investment grade bonds, which are secured debt instruments with fixed repayment terms. Operating expenses, interest on debt and repayment of principal take precedence over payments to common stock holders, and thus it is the common equity shareholder of the utility who bears the greatest risk of not receiving expected returns.

The RROE for common stock is the cost of equity. Long-standing regulatory principles recognize customers should expect to pay all costs of service. One of those costs is the cost of equity. Because equity owners are the last in line to be paid, equity owners will not earn enough to cover the cost of equity every year. But though equity owners know they will not earn the RROE every year, rates and rate-adjustment mechanisms should be established so investors have a reasonable opportunity to earn it. Over a period of several years, the rates and rate adjustment mechanisms should be designed to produce ROEs that are on average equal to the RROE. Rates and rate-adjustment mechanisms which produce expected revenues which are lower than required will subsidize customers at the expense of equity owners and are in conflict with standards of the U. S. Supreme Court and ORS 756.040 discussed above.

Q. Is PGE more risky than the sample of electric utilities you rely upon to determine your benchmark ROE estimates?

A. Yes. PGE has the same or greater risk than the average utility in the sample: PGE a) has significant exposure to the wholesale market due to its reliance on wind and hydro generation, b) is smaller than the average utility in my benchmark sample, c) has greater risk than in the past due to its anticipated larger capital expenditures program, d) has debt imputation related to certain purchased power contracts, e) has a beta that is above the sample average, f) has higher relative risk than the average utility in the benchmark sample and g) has other unique risks described by Mr. Valach and Mr. Hager.

Q. Does PGE's reliance on hydro power and wind generation increase risk?

A. Yes. Both of these sources of power are subject to unknown and uncontrollable weather conditions and thus power generated from these resources will unavoidably vary from year to year. PGE faces risk related to the cost of replacing that power with power from wholesale markets at costs that are unpredictable. Additionally, the costs of replacing this power are generally expected to be much higher than any cost savings that are expected to occur if the resources produce more power than average. In its December 18, 2012, RatingsDirect Report for PGE, S&P specifically stated PGE's reliance on power purchases and its vulnerability to hydro variability were considered when it assessed PGE's business risk profile. PGE's current PCAM mitigates but does not eliminate these unavoidable risks.

Q. Has the Oregon Commission specifically increased PGE's authorized ROE to recognize the added risk of exposure to wholesale markets?

A. Yes. In Order No. 07-015, the Oregon Commission noted PGE had significant exposure to the wholesale market, particularly as compared to PacifiCorp, and increased PGE's authorized ROE by ten basis points over PacifiCorp's to compensate for that risk exposure.

Q. Does PGE's higher percentage of purchased power increase its risk?

A. Yes. See PGE Exhibit 1201. Mr. Valach and Mr. Hager also address this issue in PGE Exhibit 1100. S&P imputes debt to PGE to reflect certain purchased power contracts. This has the result of increasing PGE's leverage and reducing its coverage ratios for ratings purposes.

Q. What is beta risk?

A. Beta is a market measure of risk that reflects the risk of holding an asset in a well-diversified portfolio. It is one commonly accepted measure of an asset's market risk.

Q. Based on beta risk, is PGE more or less risky than the average utility in your benchmark sample?

A. Based on beta, PGE is more risky than the average of my utility sample. The beta for PGE is 0.75 while the sample average beta is 0.72.

Q. Does PGE have higher relative risk than other utilities in the DCF benchmark sample?

A. Yes. Professor J. Randall Woolridge filed testimony on behalf of the California PUC Division of Ratepayer Advocates ("DRA") in Application 09-05-001 (Exhibit DRA-1, dated July 10, 2009) and in Application 12-05-001 (Exhibit DRA-001 dated August 27, 2012). In those two generic ROE proceedings, he proposed a relative risk analysis composed of two tests to determine if utility-specific risk premiums were required for specific utilities. Application of his relative risk analysis to data for PGE and the other utilities in the DCF sample indicates PGE requires a risk premium.

Q. Please explain the relative risk analyses.

A. The first relative risk test compares earned versus authorized ROEs for the most recent five-year period for PGE to earned versus authorized ROEs for other utilities in the DCF sample. In this first test, under-earning an authorized ROE is an indication of higher risk. I have conducted this first test with data for PGE and the other 19 utilities in the electric utilities sample.

In the second test, Coefficients of Variation ("CV") of earned ROEs during the five-year periods are compared. The CV, computed as the standard deviation of earned ROEs divided by the mean ROE, is a standardized measure of volatility and thus is a relative measure of risk. In this test, a higher CV indicates higher risk. I have also conducted this second test with data for PGE and the other utilities in the electric utilities sample to make the tests. The results of both tests are reported in the two-page PGE Exhibit 1204.

Q. Please discuss the results of these tests of relative risk.

A. For the first test, on average, the 19 electric utilities under-earned their authorized ROEs during this period with an average level of underperformance of -1.67 percent (average authorized ROE of 10.67 percent less the average earned ROE of 9.01 percent). By comparison, the average underperformance for PGE was -2.20 percent (average authorized ROE of 10.08 percent less the average earned ROE of only 7.88 percent). Based on this first measure of relative risk, PGE is 32 percent more risky than the other electric utilities (see PGE Exhibit 1204, page 2).

In the second test, the average CV for the 19 electric utilities was 0.19 while the CV for PGE was 0.25. This CV test also indicates the relative risk of PGE is greater than the relative risk of the other electric utilities in the sample. Based on this second test, PGE is 29 percent more risky than the other utilities in the electric utilities sample.

Q. Is PGE smaller than the average electric utility in PGE Exhibit 1201?

A. Yes. Based on market capitalization values on October 17, 2012, PGE is about 60 % as large as the average electric utility in PGE Exhibit 1201.

Q. Have studies found smaller companies are more risky than larger ones?

A. Yes. Academic studies have addressed the issue of company size and risk and found that, in general, smaller firms are more risky. The seminal version of the Capital Asset Pricing Model ("CAPM"), developed in the mid-1960s, relied upon only beta as the measure of risk. Eugene Fama and Kenneth French ("The Capital Asset Pricing Model: Theory and Evidence," *Journal of Economic Perspectives*, Volume 18, No. 3, Summer 2004 pp. 25-46) provide evidence that questions the usefulness of the simple CAPM and explain that other variables such as company size and various price ratios add to the explanation of stock returns. This problem of choosing the "correct version" of CAPM is, of course, one of the problems with using CAPM to determine costs of equity for utilities. But, notwithstanding which CAPM version is the correct one, Fama and French did find that company size as well as other factors help explain how investors price common stocks.

Morningstar has examined this issue for a number of years and found that equity investors require higher and higher returns as size becomes smaller and smaller (most recently, Morningstar, *2012 SBBI Valuation Yearbook*, Chapter 7). I also published an article, "Utility Stocks and the Size Effect - Revisited," *The Quarterly Review of Economics and Finance*, Vol. 43, Issue 3, Autumn 2003, pp. 578-582, which found smaller utilities are more risky than larger utilities. PGE Exhibit 1205 shows results from the Morningstar and Zepp studies. It shows Morningstar's estimates of beta risk and risk due to size of the companies increase as size of companies decrease. It also shows the result published in the Zepp study which found larger utilities were less risky than smaller ones. Combined, this information shows there is no "bright line" that separates smaller, higher risk utilities from larger, lower risk utilities, but that risk and RROEs increase as utilities are smaller.

Q. Have you determined a specific risk adjustment to compensate PGE for being smaller than the average utility in the sample you rely upon to conduct your DCF analyses?

A. No. PGE is 60% as large as the average utility and smaller than 12 of the 19 other utilities in the sample I use to determine benchmark DCF costs of equity. Morningstar uses data for the NYSE/AMEX/NASDAQ-listed securities reported by the Center for Research in Security Prices ("CRSP") to conduct its analysis of firm size and required returns. Data for utilities are included in the CRSP data used by Morningstar to make the analyses reported in PGE Exhibit 1205. Again, this year, Morningstar finds that risks of companies increase as size decreases. Based on this study and the size of the utilities in the sample, one should expect that PGE requires an ROE that is somewhat higher than the average utility in the sample. While I do not determine a specific risk premium addition for size, I do take this evidence into account when determining that the appropriate ROE for PGE is above the average cost of equity for the benchmark sample.

Q. Does PGE face greater risk due to its evolving mix of power resources?

A. Yes. Moody's states that PGE's primary challenge arises from financing an evolving mix of power resources. During the next ten years, PGE's current mix of resources and production percentages will change with Boardman ceasing coal-fired operations in 2020 and as PGE meets mandates set in Oregon's Renewable Portfolio Standards. Moody's anticipates that as RFP results are returned and viable solutions are chosen, the primary credit challenge that PGE will face exists in financing and/or construction of the significant changes in the Company's resource portfolio (Moody's Investor Service, Credit Opinion: Portland General Electric 02 July 2012). From an equity investor's perspective, the need for additional investments increases uncertainty about future earnings and the risk increases.

Q. Does PGE plan to invest significantly more than in the past?

A. Yes. Mr. Valach and Mr. Hager address this issue in their testimony in PGE Exhibit 1100.

Q. Do you have any comments about the impact of decoupling on the need for a risk premium?

A. Yes. In Order No. 09-020, the Commission found that adoption of decoupling justified an ROE reduction of ten basis points for PGE. It is clear that ratings agencies, investors and utilities prefer rate designs with decoupling to traditional rate designs when utilities have risks of losing load due to energy conservation efforts. I have two observations which indicate such a reduction in ROE is no longer appropriate.

First, though Moody's said it views decoupling mechanisms as credit positive for utilities, it noted that similar mechanisms exist for a growing number of utilities around the country. Before determining if a negative risk premium (an ROE lower than the benchmark cost of equity for a sample of electric utilities) is still required due to decoupling, it should be determined if the risk-reducing benefits of decoupling are already in the benchmark costs of equity estimates. PGE Exhibit 1201 shows 16 of the 20 utilities in the sample already have decoupling mechanisms or alternative fixed cost recovery mechanisms available in at least one state in which they do business. Given the push for conservation and other energy efficiency measures, it is reasonable for investors to expect more regulators to approve such rate designs in the future. The data in PGE Exhibit 1201 and reasonable expectations about the future indicate cost of equity estimates for the majority of utilities in the sample already reflect whatever benefit is provided by such rate designs.

Second, decoupling may be required simply to offset higher risks that occur when energy conservation initiatives are pressed by environmental activists, government agencies and utilities. A recent analytical study conducted by the Brattle Group suggests that may be the case. (The Brattle Group, *The Impact of Decoupling on the Cost of Capital: An Empirical Investigation,* Discussion Paper, March 2011). Though decoupling may offset some of those risks, the authors expressed concern that there was no empirical evidence that decoupling programs fully offset the risks of such programs and reduced the net cost of capital. Their robust statistical tests did <u>not</u> support the position that the cost of capital is reduced by the adoption of decoupling. Their analyses found that if decoupling decreases the cost of capital, the effect must be minimal because it is not detectable statistically. It appears investors are in favor of decoupling programs because they offset higher risks due to conservation programs but the tests show those investors do not expect all of those risks to be fully offset.

Q. What is your recommended risk adjustment for PGE?

A. In Order No. 07-015, the Commission determined that PGE requires a risk premium of ten basis points to compensate for its significant exposure to the wholesale market. That risk continues and increases due to uncertainty of production from wind projects as well as hydro projects. PGE is more risky than in the past when it had a much more modest capital expenditures program, is more risky because it is only 60% as large as the benchmark sample and has a higher than average percentage of purchased power. PGE Exhibit 1201 shows PGE has an S&P business risk profile that is the same as most of the utilities in the sample, an S&P financial risk profile that is the same as eleven of the other 19 utilities in the sample and a bond rating that is slightly higher than average. Quantitative estimates of risk as measured by beta risk and two relative risk tests indicate PGE is more risky than the average utility in the benchmark sample. Taking into account PGE's exposure to all of these various positive and possible negative risks, I conclude PGE has a cost of equity that is in the upper half of my estimated range of costs of equity for electric utilities.

III. DCF Equity Cost Estimates

Q. Do you have preliminary comments related to the use of the DCF model to determine equity cost estimates?

A. Yes. Given the weight the Commission has given to the DCF model in recent Oregon decisions, I begin my RROE study with my DCF estimates. However, I strongly recommend the Commission consider several versions of the DCF model and other useful information to determine a fair ROE for PGE. Whatever DCF model is employed, the estimated costs of equity depend crucially on assumptions about how investors determine future growth. We do not, however, know exactly how investors form their opinions about these growth rates. Not only are there unavoidable difficulties with estimating growth rates but also investors may consider information and financial models other than the DCF model to price stocks. Other methods assume investors make decisions in different ways and thus it is appropriate to make different abstractions to model investor behavior. There is no guarantee that any particular method is the "right" one and thus superior to others. It follows then that other reasonable approaches should be considered.

At a minimum, RP financial models and data for forecasted, authorized and earned ROEs in PGE Exhibit 1215 should be used as a check on the results of DCF models employing specific assumptions and methods. If the equity costs produced with DCF methods and assumptions chosen by an analyst are significantly different than cost of equity estimates resulting from application of other financial models and checks on the reasonableness of the results made by examination of forecasted, authorized and earned ROEs, those DCF results should be seriously questioned or rejected.

Q. Please summarize your DCF estimates.

A. My DCF estimates are provided in PGE Exhibits 1208, 1209 and 1210. The estimates presented in PGE Exhibit 1208 are based on application of the constant growth DCF model and forward-looking estimates of growth. PGE Exhibit 1208 relies on an average of Value Line forecasts of growth and analysts' forecasts of EPS growth reported by Zacks, Yahoo! Finance and Reuters and finds the benchmark cost of equity is 10.1%. PGE Exhibit 1209 is a two-stage DCF approach similar to the two-step method the Federal Energy Regulatory Commission ("FERC") used to estimate equity costs in the past. It is a multi-stage DCF model which relies upon initial growth based on averages of Value Line and analysts' EPS growth forecasts and terminal growth based upon expected GDP growth. This method finds the estimated DCF equity cost for the benchmark sample is 10.1%. PGE Exhibit 1210 is a multi-stage analysis which assumes three different stages of growth are expected by investors and that ultimately all dividends per share ("DPS") will grow at the same rate as growth in the economy as a whole. With this approach, the indicated average DCF equity cost estimate is 10.3% for the sample.

Q. Please explain the constant growth DCF method of estimating the cost of equity.

A. The constant growth DCF model computes the cost of equity as the sum of an expected dividend yield ("D_1/P_0") and expected dividend growth ("g"). The expected dividend yield is computed as the ratio of next period's expected dividend ("D_1") divided by the current stock price ("P_0"). In some jurisdictions, D_1 is estimated with formula (1):

1) Equity Cost $= D_0/P_0 \times (1 + g) + g$,

where D_0/P_0 is the current dividend yield and D_1/P_0 is found by increasing the current yield by the growth rate. It is my understanding that in recent cases, Oregon Staff has estimated

D_1 with independent forecasts of D_1 and thus, conceptually would use formula (2) to implement the model:

2) Equity Cost = D_1/P_0 + g.

To facilitate comparison of my equity cost estimates with those of Staff, I have used this second approach in this case. The constant growth DCF model and multistage DCF models are derived from the valuation model shown in equation 3 below:

3) $P_0 = D_1/(1+k) + D_2/(1+k)^2 + \ldots + D_\infty/(1+k)^\infty$,

where k is the cost of equity; P_0 is the current stock price, $D_1, D_2, \ldots D_\infty$ are the cash flows expected to be received in periods 1, 2, . . . ∞, respectively. Equation (3) is equivalent to equation (4) when it is expected that the stock will be sold at price P_n at the end of period n:

4) $P_0 = D_1/(1+k) + D_2/(1+k)^2 + \ldots + (D+P)_n/(1+k)^n$,

In the case of the constant growth DCF model, DPS, EPS, market price per share ("MPPS") and book value per share ("BVPS") are all assumed to grow at the same rate in every future period. In multi-stage DCF models, after an initial period (or periods) has passed, future DPS, EPS, BVPS, and MPPS are assumed to grow at faster or slower rates of growth than in the initial stage (or stages).

Q. How did you compute the dividend yields?

A. My dividend yield estimates are denoted as D_1/P_0 in equation 2) above. These estimates are reported in PGE Exhibit 1206. My dividend yields are averages of the highest and lowest dividend yields which occurred during the period September 1, 2012 to November 30, 2012. To be consistent with recent OPUC Staff testimony, estimates of D_1 are based on Value Line's estimated dividends for next year which I adjusted to compensate for the time value of money.

Q. Why have you adjusted the values for D_1 for the time value of money?

A. This adjustment is required because equation 3) above assumes dividends are paid once a year but investors receive dividend payments on a quarterly basis. If a utility pays a dividend of $100 per year, investors would prefer to be paid $25 every quarter instead of $100 at the end of the year. Prices investors pay for utility stocks reflect the benefit investors receive by utilities paying dividends every quarter but equation 3) assumes the $100 is paid only once a year. My calculation adjusts the dividend upward by just enough to offset the time value of receiving the $100 in four quarterly installments of $25 each.

The values adopted for D_1 must also reflect the fact that DPS are expected to increase over time since all of the utilities in the sample are projected to have positive growth in the future. I recognize that potential positive growth by adopting Value Line's forecasts of dividends for 2013. Other methods could be adopted to recognize the near-term growth in DPS, but I have used this conservative approach to minimize controversy. A general discussion of the various approaches that could be taken is provided in Roger Morin, *New Regulatory Finance,* pages 343-349.

Q. How did you estimate growth rates?

A. Growth rates used with the DCF model should be based on the best available forecasts of future growth. A number of investor services report consensus averages of analysts' forecasts of EPS growth. For my analysis, I have relied on an average of the long-term EPS growth rates reported by Value Line and an average of the long-term EPS growth rates reported by Zacks, Reuters and Yahoo! Finance. PGE Exhibit 1207 provides a list of the Value Line and analysts' forecasts reported for the sample utilities. Column (f) of PGE Exhibit 1207 reports averages of the Value Line forecasts and available analysts' forecasts.

Taken together, the average of the Value Line forecasts (column (a)) and analysts' forecasts (column (e)) is 5.7% at this time.

Q. How did you compute your average constant growth DCF estimate?

A. Initially I added together the average growth rate estimates from PGE Exhibit 1207 and dividend yields from PGE Exhibit 1206 to compute a DCF cost of equity estimate for each of the 20 utilities. See PGE Exhibit 1208. Next I considered whether any of the estimates are less attractive than investment grade debt issues. It is common sense that investors would not buy shares of more risky common stocks if they could instead buy less risky investment grade bonds. In general, the Federal Energy Regulatory Commission ("FERC") found a cost of equity estimate that is less than 100 basis points above the cost of bonds is not credible. But it is also appropriate to eliminate any exceptionally high cost of equity estimates if they can be identified (see 2010 Southern California Edison Order (131 FERC-61020) at paragraphs 54 to 58). Based on my comparison of cost of equity estimates and expected costs of bonds (see PGE Exhibit 1211), I determined it might be appropriate to eliminate the cost of equity estimate for IDACORP. But I do not have clear criteria to determine if an equity cost is "too high" and thus included all estimates in my estimate of the average DCF cost of equity of 10.1% (see PGE Exhibit 1208).

Q. Please explain your second DCF analysis.

A. My second DCF analysis is a two-stage DCF analysis similar to the two-step DCF method relied upon by the FERC in a number of cases and fully discussed in *Southern California Edison Company*, Opinion No. 445, 92 F.E.R.C. 61,070 (2000) and in Opinion 396-B, *Northwest Pipeline Company*, 79 F.E.R.C. 61,309 (1997). The FERC two-step approach differs from the constant growth DCF model in that it assumes that investors will expect terminal growth to be different than initial growth. In deriving its two-step approach, the FERC recognized that investment houses use more complex three-stage models in which the first and second stages could have a length of possibly 20 years and the final stage growth is the long-term growth rate of the economy. In Opinion 396-B, the FERC expressed its preference for the simpler two-step model that, in effect, combined the first two stages of the more complicated three-stage model used by investment houses. *Northwest Pipeline Company*, 79 F.E.R.C. 61,309 (1997). The concepts I rely upon for my two-stage DCF analysis are as follows:

- Adopt averages of high equity cost estimates and low equity cost estimates to determine a range of cost of equity estimates.
- Determine each cost of equity estimate with a two-stage DCF analysis in which the initial growth rate is given a weight of two-thirds and the terminal growth rate is given a weight of one-third.
- Adopt the FERC method of relying on EPS growth forecasts to determine initial growth rates.
- Adopt the FERC method of relying on a GDP forecast as the terminal growth rate estimate.

In making each high (low) equity cost estimate, I rely upon the highest (lowest) forecast in the range of growth rates reported in PGE Exhibit 1207. In deciding whether to include all estimates, I considered attempting to identify outliers but chose instead to keep all estimates in the analysis.

Q. How did you estimate GDP growth for the second stage of your two-stage analysis?

A. When FERC gives a weight of one-third to GDP growth it is assumed that the second stage will not start for many years into the future and therefore investors relying on this method would focus primarily on expected long-term GDP growth, not GDP growth expected during the next ten or fifteen years.

In determining my estimate of GDP growth, I initially considered the method Staff of the Arizona Corporation Commission ("ACC") has used for at least six years to determine long-term GDP growth one would expect investors to rely upon[1]. This method assumes an average of past annual GDP growth rates is a reasonable indicator of growth investors would expect in the future terminal period. In March 2012 testimony in the Arizona Water Case, ACC Staff determined that average historical GDP growth was 6.5% and used that value as its estimate of terminal growth investors would expect in the future.

Q. Do you consider the ACC Staff approach appropriate when determining an estimate of growth in a multi-stage DCF analysis?

A. Yes. It is important to recognize that the GDP growth forecast being used in this model is an estimate of growth that does not start for at least eleven years into the future[2]. Generally, estimates of future GDP growth reported by Federal agencies and reported by Blue Chip are for periods that start before 2023 (eleven years into the future). As discussed above, Value Line and others anticipate a slow recovery in GDP and thus GDP growth may not be "back to normal" for many years. As a result, because we are attempting to determine the best

[1] For example, this approach was used by ACC Staff in the 2007 Direct Testimony for ACC Staff of Steven P. Irvine, in Docket No. W-01303A-07-0209 (Arizona-American Water Company), dated October 15, 2007, and 2012 Direct Testimony for ACC Staff of John A. Cassidy, in Docket No. W-01445A-11-0310 (Arizona Water Company), dated March 13, 2012.

[2] The eleven year period assumes a cost of equity of 11.0% and EPS growth in the first eleven years account for two-thirds of the annual cash flows in equation (3). A lower cost of equity would indicate the initial period is longer than 11 years.

forecast of GDP growth investors expect during a period starting many years from today, that forecast should be for a period that starts (not ends)[3] at least eleven years into the future.

Q. Have you used the ACC Staff estimate of 6.5% as your estimate of terminal growth expected by investors?

A. No. To be conservative, I have assumed terminal GDP growth expected by investors will be 50 basis points lower than it has been in the past. By making this assumption, I assume future GDP growth will be 6.0% instead of 6.5%.

Q. What are the results of your two-stage DCF analysis?

A. The results are reported in PGE Exhibit 1209. The average of the high and low equity cost estimates is 10.1%.

Q. Why are the differences between the low and high cost of equity cost estimates so wide?

A. They are wide because the range of cost of equity estimates is based on the highest and lowest forecasts of growth from PGE Exhibit 1207, not consensus estimates of growth. While it is generally not appropriate to base an equity cost estimate on either of those extreme values, the average of those estimates may provide a useful indication of the cost of equity. The indicated average cost of equity for the sample is 10.1% and thus the indicated cost of equity for PGE is in excess of 10.1%.

Q. Please describe your third DCF analysis.

A. My third DCF analysis is developed in PGE Exhibit 1210. This analysis determines the cost of equity by finding the internal rate of return that is consistent with different growth rates in three stages. Initially it is assumed that an average of recent prices ("P_{2012}") and *Value Line's* forecasted dividends for 2013 are appropriate for the analysis. Growth rates

[3] For example, the December 1, 2012 Blue Chip long-term forecast of GDP goes out no further than the five-year period 2019-2023.

adopted for the first stage (for 2014–2018, the next five years) are the averages of forecasted EPS growth rates reported in PGE Exhibit 1207. I have assumed—as does the FERC—that EPS growth is the critical concern of knowledgeable investors who realize that earnings enable the utility to increase dividends. PGE Exhibit 1210 reports the first and last forecasted dividend for this period (D_{2014} and D_{2018}) for each utility.

The second stage is a transition stage in which growth in the first stage is assumed to gradually increase (or decrease) toward a terminal growth rate over a period of ten years (2019 to 2028). PGE Exhibit 1210 reports the first and last forecasted cash distributions for this period (D_{2019} and $(P+D)_{2028}$) for each utility. The terminal growth rate is assumed to be GDP growth of 6.0% which I discussed above. In 2028 it is also assumed that the stocks are sold and the prices paid for those stocks anticipate that DPS growth will equal GDP growth in all future periods. The selling price for the respective stocks reflects GDP growth during that final (third) stage.

Q. What is your average cost of equity estimate based on this third DCF approach?

A. This analysis indicates an average cost of equity estimate for the benchmark sample companies of 10.3% and thus the indicated cost of equity for PGE is above 10.3%.

IV. Risk Premium Equity Cost Estimates

Q. Please turn to your risk premium equity cost estimates. Please summarize the equity cost estimates you make with this approach.

A. I make three RP equity cost estimates that indicate the cost of equity for PGE falls in a range of 10.0% to 11.1%. We do not know exactly what information investors use when they use risk premium approaches to price common stocks and thus I present three alternative versions of the method.

Q. In general, how is a cost of equity estimate determined with a risk premium approach?

A. A risk premium cost of equity estimate is made by first determining what the relationship has been between costs of equity and a particular interest rate over a period of time. To implement a risk premium approach, generally, it is assumed that the past relationship will continue into the future. That historical relationship is then combined with a current forecast of the particular interest rate to predict the current cost of equity.

Q. Are risk premium approaches widely used in the financial community?

A. Yes.

Q. Please compare interest rates in the past to interest rates expected in 2014–2015.

A. In recent years, interest rates have dropped to very low levels when compared to the past. From 1980 to 2002, annual average rates for 30-Year Treasury bonds, for example, ranged from 5.43% to 13.45%. (See PGE Exhibit 1202.) In 2009, that annual average dropped to 4.08% during the recession, dropped further in 2011 to 3.91% and dropped below 3.0% in 2012, based on fears of a second recession and actions of the Federal Reserve. Notwithstanding these current low rates, 30-year Treasury rates are expected to bounce back up in 2014–2015. Analysts at Value Line expect that future average to be 4.60%. The average consensus estimate made by analysts surveyed by Blue Chip is 3.95% and an average of forecasts reported by Global Insight is 4.02%. For my analyses, I have relied upon the average of all three forecasts which is 4.19% (see PGE Exhibit 1211).

Q. Why have you used the period 2014–2015 to determine interest rates for your RP analyses?

A. The cost of equity estimates should be for the period when new rates will be in effect. The first year in that future period is 2014. I do not know when PGE will file for different rates but recognize the new rates set for 2014 may be in effect for more than one year. As a result, I have adopted the period 2014-2015 for my RP analyses.

Q. Do you expect risk premiums to vary inversely with interest rates?

A. Yes. There is a theoretical reason and many sources of empirical data to support equity cost risk premiums increasing as interest rates decrease.

Q. Why is this inverse relationship between interest rates and risk premiums important at this time?

A. It is important because future 30-year Treasury security rates are expected to be lower than the averages of long-term Treasury security rates that prevailed during the periods used to determine risk premium analyses. The average of 30-year Treasury security rates expected in 2014-2015 of 4.19% is higher than rates are currently, but lower than Treasury security rates were during most years used to determine historical relationships between Treasury security rates and equity costs (and thus, risk premiums). As a result, risk premiums today are expected to be higher than in the past.

Q. What is the theoretical reason risk premiums are expected to increase when interest rates decrease?

A. The theoretical support is found in Myron Gordon and Paul Halpern's article, "Bond Share Yield Spreads Under Uncertain Inflation", American Economic Review, Vol. 66, No. 4, September 1976, pp. 559-565. In that article, Gordon and Halpern explained that as investors expect higher uncertain inflation, interest rates would increase to reflect greater uncertainty and higher expected inflation, but costs of equity would not increase as much because stocks—but not bonds—provide a hedge against inflation. This common sense theory provides a strong conceptual basis for the empirical analyses discussed and applied below. I note that Gordon and Halpern concluded their article with empirical support for the theory based on differences in bond costs and equity costs for electric utilities. They found that as Aaa bond rates increased, risk premiums for electric utilities decreased.

Q. Have other authors found an inverse relationship between risk premiums and interest rates?

A. Yes. Harris and Marston, "Estimating Shareholders Risk Premia Using Analysts' Growth Rates," Financial Management, Summer 1992 found an inverse relationship as did Roger Morin in a study reported in chapter 4 of his 2006 book, New Regulatory Finance.

Q. Has OPUC staff addressed this issue?

A. Yes. In UT-85, Phil Nyegaard stated, "Theory suggests that relatively high inflation narrows the risk spread between stocks and bonds, and that relatively low inflation widens that spread." Based on this theory and data from Ibbotson and Sinquefield, Mr. Nyegaard determined the risk premium for the stock market as a whole was expected to be above the long-term average because investors expected inflation (and future bond rates) to be lower than the long-term average at the time he prepared that testimony (Staff/3 Nyegaard/14, UT-85, January 20, 1989).

Q. Have other regulators determined that risk premiums vary inversely with interest rates?

A. Yes. The California Public Utility Commission also determined that risk premiums vary inversely with interest rates. In 1997, the CPUC found that costs of equity for energy utilities move in the same direction as interest rates but by less. The table below summarizes Table 3 of Decision 97-12-089, which established costs of capital for Pacific Gas & Electric Company ("PG&E").

Table 2

Year	Forecasted Interest Rate	Change	Authorized ROE	Change
1991	9.76%		12.92%	
1992	9.10%	-66	12.65%	-27
1993	8.32%	-78	11.85%	-80
1994	6.76%	-156	10.92%	-90
1995	8.37%	+161	12.05%	+110
1996	7.29%	-108	11.60%	-45
1997	7.92%	+63	11.60%	0
1998	7.81%	-74	11.20%	-40

In all but one case, the CPUC found that equity costs move in the same direction as interest rates, but the change in the cost of equity was less than the change in interest rates. In California, PUC Decision 02-11-027 confirmed that its practice was to adjust returns on equity for energy utilities by one-half to two-thirds of the change in the benchmark interest rate.

Q. Please describe your first risk premium analysis.

A. The first approach I use is based on a method routinely used by the California Division of Ratepayer Advocates ("DRA") Staff to determine costs of equity.[4] This DRA Staff method relies on annual averages of past recorded book returns on equity for a sample of utilities as proxies for costs of equity at different points in time. It assumes that regulators adopt rates and rate adjustment mechanisms that give utilities reasonable opportunities to earn their costs of equity and thus—though each individual utility may earn more or less than its cost of equity in a given year—the average annual costs of equity estimates for the sample may provide useful proxies for the annual average costs of equity for the sample.

Q. How did you implement this method in this case?

A. To implement this method, I adopted averages of actual ROEs for electric utilities reported in "Composite Statistics: Electric Utility Industry," which Value Line published in various issues of the Value Line Investment Survey during 1997 to 2012.[5] Value Line determines ROEs by dividing earned returns by year-end equity and thus these ROE estimates provide conservative estimates of ROEs which should be computed on a mid-period basis.

Q. What are the results of this first RP analysis?

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[4] For example, see Division of Ratepayer Advocates, California PUC Report on the Cost of Capital, San Jose Water June 2006, Application 06-02-014.

[5] If Value Line revised the reported average, I relied on the most recent ROE reported.

A. This risk premium analysis indicates the estimated future average cost of equity for the electric utilities falls in a range of 10.0% to 11.1%. Since PGE is more risky than a typical electric utility, this provides a conservative estimate of the range in which PGE's cost of equity falls at this time. As discussed above, risk premiums are expected to increase as interest rates decrease. PGE Exhibit 1212 is consistent with this expectation. The estimated average risk premium for the most recent 5-year period is higher when the average of interest rates was lower. The average of interest rates was lower in 2007-2011 than in the full fifteen-year period, 1997-2011. To be conservative, I determined a range of risk premiums that included data for the full 15-year period as well as the most recent 5-year period. The results of this analysis are reported in PGE Exhibit 1212. Forecasts of 30-year Treasury bond rates expected in 2014 to 2015 are reported in PGE Exhibit 1211.

Q. Please discuss the second RP analysis.

A. The second risk premium analysis is a market approach. It is based on an average of differences between annual total realized returns for an index of electric utilities and yields that could have been obtained on long-term Treasury bonds at the beginning of the respective years. This approach recognizes that the annual actual risk premium in any particular year will probably not equal the required risk premium but that, over a long period of time, the average of those annual actual risk premiums may provide a good estimate of the average risk premium that was required during that period.

Initially, I computed two preliminary average risk premiums, which are reported in PGE Exhibit 1213. The first preliminary risk premium is for the period ending in the year 2000 when Moody's stopped updating its index for electric utilities. The second preliminary estimate was for the period ending in 2011. It is based on data for the Moody's index through 2000 and an index of nine utilities from the electric utilities sample that did not cut dividends during the period 2000 to 2011.

The preliminary analyses determined average risk premiums and thus did not incorporate the expectation that risk premiums vary inversely with interest rates. Because the long-term Treasury rate of 4.19% that is expected in 2014-2015 is lower than the average Treasury rate of 6.21% for the period 1950 to 2011 and lower than the average Treasury rate of 6.54% during the period of the original study, the future risk premium is expected to be higher than the simple average RP based on past data. To incorporate this additional information, I adjusted upward the risk premium estimates by assuming the cost of equity changes by half as much as the difference in Treasury bond rates. This adjustment is consistent with the California PUC orders I discussed above. Based on these estimates, the benchmark equity cost range is 10.5% to 11.1% and the indicated cost of equity for PGE is above the middle of that range. (See PGE Exhibits 1213 and 1216.)

Q. What is the conceptual basis for your third RP analysis?

A. The third RP approach relies on authorized ROEs as proxies for the costs of equity for electric utilities. In Docket No. ER93-465-000, Staff of the FERC adopted authorized ROEs as proxies for costs of equity to implement its risk premium approach. Professor Roger Morin has also adopted authorized returns on equity as proxies for costs of equity for electric utilities to conduct a risk premium analysis. Roger Morin, *New Regulatory Finance,* Chapter 4, Public Utility Reports, Inc., 2006. My analysis is similar to Dr. Morin's approach which found risk premiums increase (decrease) as interest rates decrease (increase).

Q. Please discuss Dr. Morin's approach.

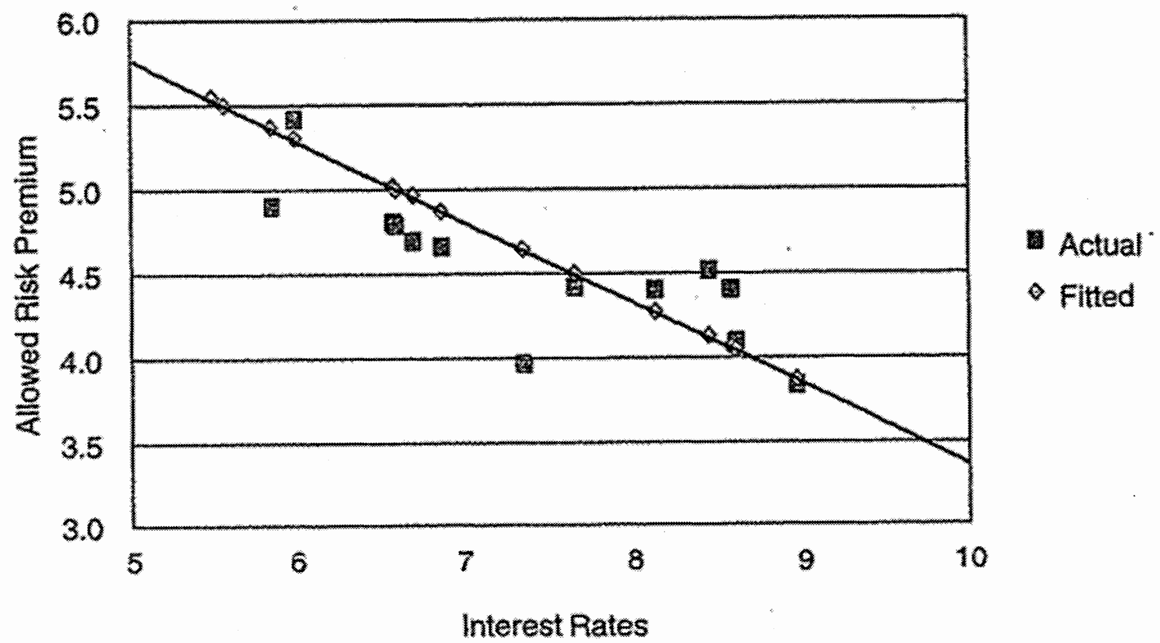
A. Dr. Morin reports that risk premium cost of equity estimates have been relied upon in regulatory proceedings for many years and are widely used by analysts, investors and expert witnesses. He notes that the RP approach to estimating the cost of equity derives its usefulness from the simple fact that while equity return requirements cannot be readily quantified at any given time, the returns on bonds can. Thus, if the risk premium is known, it can be used to produce a useful estimate of the cost of equity. In one of his risk premium techniques, Dr. Morin relies on authorized returns on equity when determining risk premiums. *New Regulatory Finance*, page 123. Professor Morin reports the following statistical relationship between risk premiums (RPm) and Treasury rates (Yield) for the period 1987 to 2005 for electric utilities:

(5) RPm = 8.2049 – 0.4833 x Yield

where averages of allowed equity returns reported by Regulatory Research Associates are adopted as annual proxies for costs of equity to compute the estimates of RPm. Morin reports that this regression had an R^2 (coefficient of determination) of 81%. This means that 81% of the variability in risk premiums was explained by the estimated regression line. He also reports the slope of the regression line had a t-statistic of -8.4%. This standard statistical test means the slope is significantly different than zero and we have a high degree of confidence that risk premiums vary inversely with Treasury bond yields.

To obtain a cost of equity estimate, Dr. Morin inserts an appropriate Treasury bond yield in his estimated equation. He further explains, “Figure 4-4 shows the clear inverse relationship between the allowed risk premium and interest rates revealed in past common equity decisions.” The risk premium method presented by Dr. Morin is discussed in Section 4.5 of his 2006 book and is shown graphically in Figure 4-4 reproduced below:

FIGURE 4-4
ALLOWED RISK PREMIUM VS INTEREST RATES
1987–2005



The risk premiums reported in the figure are equity risk premiums implied by consideration of authorized ROEs relative to contemporaneous yields on long-term Treasury bonds.

Q. Is your third RP approach consistent with the analysis Dr. Morin presented in his book?

A. Yes. My third RP analysis is consistent with academic research and the analysis presented by Dr. Morin in *New Regulatory Finance*, but relies on a larger sample of 583 individual litigated decisions instead of annual averages of those decisions used in Dr. Morin's analysis. I have also based my analysis on long-term Treasury bond rates six months prior to the dates decisions were issued by the commissions to recognize the practical constraints of regulatory proceedings, where DCF, RP and other financial models used to determine authorized ROEs are based on data available several months prior to the issue of orders. Long-term Treasury bond rates are adopted to determine the risk premiums.

Q. What specific study did you conduct?

A. I conducted an analysis with data for the period 1984 to 2012. This period is slightly longer than the 1987 to 2005 period Dr. Morin used in his analysis. The results of my analysis are shown in PGE Exhibit 1214. This risk premium approach indicates a typical electric utility can expect to have a cost of equity of 10.3% in 2014 - 2015.

Q. Did you also consider a risk premium estimate using the equation estimated by Dr. Morin?

A. Yes. Inserting the expected Treasury bond yield of 4.19% from PGE Exhibit 1211 in the formula estimated by Dr. Morin indicates a risk premium equity cost estimate for a typical electric utility of 10.4%. Applying Dr. Morin's result indicates that my analysis provides a conservative estimate of the cost of equity.

V. Authorized, Forecasted and Earned ROEs

Q. Have you made any checks on the reasonableness of your DCF and RP equity cost estimates?

A. Yes. I present the data in PGE Exhibit 1215 to provide such a gauge.

Q. Does PGE Exhibit 1215 provide perspective about what is a fair ROE for PGE at this time?

A. Yes. As I noted above, the U. S. Supreme Court's decisions in the 1923 Bluefield Waterworks case and 1944 Hope Natural Gas Company case, as well as ORS 756.040 set forth three standards for a fair ROE. In effect, Oregon and the U.S. Supreme Court require the Commission to determine rates and rate adjustment mechanisms for PGE that allow the Company to have a fair chance to earn its opportunity cost of capital, *i.e.*, returns investors could expect to earn if they invest in other enterprises of comparable risk. A benchmark sample of those other enterprises of comparable risk is the guideline sample of 19 other electric utilities in the sample.

Three obvious measures of the opportunity cost of equity that are available to investors are the ROEs these benchmark utilities are currently earning, the ROEs these utilities are authorized to earn, and ROEs Value Line forecasts will be earned in the future. If regulators authorize rates and rate adjustment mechanisms that allow utilities a reasonable chance to earn their costs of equity, because PGE is more risky than the benchmark sample, a) an average of earned ROEs for the sample (less PGE), b) an average of ROEs forecasted to be earned by Value Line, or c) an average of authorized ROEs provide information about the minimum ROE that should be authorized for PGE.

PGE Exhibit 1215 provides a list of currently earned ROEs reported by AUS Utility Reports in November 2012 for the utilities in PGE Exhibit 1201. An earned ROE, however, does not provide a useful estimate of the cost of equity if it is less than the cost of investment grade debt. Black Hills earned only 2.7% during the period reported by AUS Utility Reports. A 2.7% ROE is clearly below any reasonable measure of the cost of equity and should be disregarded. Once the earned return for Black Hills is removed from consideration, the remaining average of earned ROEs is 10.2%.

PGE Exhibit 1215 also reports the most recently authorized ROEs for the 20 sample utilities as reported by AUS Utility Reports[6]. Based on these data, the average of authorized ROEs for the sample without PGE is 10.4%. At page 47 of Order No. 07-015 (the UE-180 case), the Commission stated it would not rely upon rates authorized in other jurisdictions to determine ROEs, but will use those decisions to gauge the reasonableness of its decision. As PGE is more risky than the sample, these data indicate PGE requires an ROE above 10.4%.

Finally, PGE Exhibit 1215 reports Value Line forecasts of future expected ROEs which are computed on year-end equity. I restated the Value Line forecasted ROEs using the formula usually attributed to FERC to put the forecasted ROEs on a mid-period basis. An average of those forecasted ROEs (without PGE in the sample) is 10.6%.

Q. Are the authorized ROEs reported in PGE Exhibit 1215 the result of applying specific financial models?

A. No. The authorized ROEs are the results of judgments made by regulators who heard evidence in regulated proceedings or from settlements of parties in those cases.

[6] AUS Utility Reports does not provide an average of authorized ROEs for Northwestern Energy. That value is taken from ROEs reported by Value Line.

Q. Are the earned ROEs reported in PGE Exhibit 1215 the result of applying specific financial models?

A. No. The realized ROEs are the results of the revenue requirements determined in various cases, rates and rate adjustment mechanisms which were approved and realization of subsequent uncertainty in demands for service and costs.

Q. Are the Value Line forecasted ROEs reported in PGE Exhibit 1215 the result of applying specific financial models?

A. No. Forecasted ROEs depend on Value Line's determination of how well the various utilities are expected to perform in the future and thus take many different factors into account.

Q. Please summarize what is shown in PGE Exhibit 1215.

A. In sum, the evidence in PGE Exhibit 1215 provides direct estimates of the opportunity cost of equity that ORS 756.040 and the U.S. Supreme Court have found should be considered in determining a fair rate of return on equity. The ultimate test of a fair ROE is whether the rates and rate adjustment mechanisms authorized for PGE by the Oregon PUC give PGE a reasonable opportunity to earn the rate of return investors could expect to earn if they invested in another utility of comparable risk. The average of authorized returns, realized ROEs resulting from commission decisions and forecasted ROEs reported in PGE Exhibit 1215 provide a gauge indicating the equity cost estimates I present above are indeed reasonable.

VI. Summary and Conclusions

Q. Please summarize your testimony.

A. The fair rate of return for PGE should be determined by recognizing that PGE faces a number of risks previously recognized by the Commission, quantitative analyses of risk, and other risks discussed by Mr. Valach, Mr. Hager, and me. PGE continues to require a risk adjustment of 10 basis points to compensate for its exposure to the wholesale market. Once decoupling and other risk factors are considered, on net, PGE has an RROE that is higher than the average cost of equity for my benchmark sample.

My equity cost estimates are summarized in PGE Exhibit 1216. Initially, I turned to benchmark DCF estimates based on data for a sample of 20 electric utilities. My first estimate for the benchmark sample of 10.1% is based on the constant growth DCF model and consensus estimates of future EPS growth reported by Value Line and three institutions that report analysts' forecasts of EPS growth. My second benchmark DCF estimate of 10.1% is based on a two-stage DCF model similar to the one used by FERC, a range of growth estimates presented in PGE Exhibit 1207, and a forecast of future GDP growth. This approach assumes investors expect two-stage growth with growth in the terminal stage being growth in GDP. Based on this analysis, the indicated required ROE for Portland General is above 10.1%. My third DCF approach determines an internal rate of return for each of the benchmark sample companies from an examination of expected growth in three future stages. It assumes investors expect growth rates that gradually increase or decrease toward future GDP growth. Based on that analysis, the average equity cost for the sample is 10.3% and the indicated RROE for PGE is above 10.3%.

In section IV, I explain why risk premiums are expected to vary inversely with interest rates and summarize Gordon and Halpern's theory that supports such a relationship. I then present three risk premium studies that used different methods to determine risk premiums: one bases risk premiums on realized book returns on average equity, one determines risk premiums from averages of holding period returns and the other determines risk premiums from a statistical analysis of past authorized returns for electric utilities. Taken together, the risk premium analyses support a benchmark ROE range of 10.0% to 11.1% and a RROE for PGE above the mid-point of that range.

I also provide some perspective and checks on my estimates of RROEs. I show that if authorized, forecasted and earned ROEs for companies in my DCF benchmark sample were considered along with higher risk for PGE, the indicated RROE for PGE would be above the mid-point of a range of 10.2% to 10.6%. Taking into account all of the data presented in PGE Exhibit 1216, I estimate PGE's cost of equity falls above the mid-point of a range of cost of equity estimates of 10.0% to 10.7%.

Q. Is PGE'S requested ROE of 10.0% reasonable?

A. Yes, it is. A 10.0% ROE is at the bottom of my range of equity cost estimates and thus is a conservative request.

VII. Qualifications of Thomas M. Zepp

Q. What is your profession and background?

A. I am an economist and Vice President of Utility Resources, Inc., a consulting firm. I received my Ph.D. in Economics from the University of Florida. Prior to jointly establishing our consulting firm in 1985, I was a consultant at Zinder Companies from 1982-1985. Between 1976 and 1982, I was a senior economist on the staff of the Oregon Public Utility Commissioner (now Commission). In that position, I conducted studies and prepared testimony on a number of economic and financial issues and estimated fair rates of return for many of the utilities regulated by the Commissioner. Prior to 1976, I taught business and economics courses at the graduate and undergraduate levels at the University of Florida, Central Michigan University and the Joint Graduate Program of Armstrong and Savannah State Colleges.

I have been deposed or testified on various topics before regulatory commissions, courts and legislative committees in states of Alaska, Arizona, California, Colorado, Georgia, Hawaii, Idaho, Illinois, Iowa, Kentucky, Minnesota, Montana, Nebraska, Nevada, New Mexico, Oklahoma, Oregon, Tennessee, Utah, Washington, West Virginia, and Wyoming, before two Canadian regulatory authorities and before four Federal agencies. In addition to cost of capital studies, I have testified as to values of utility properties, incremental costs of energy and telecommunications services, and appropriate rate designs.

Q. What cost of capital studies have you prepared before?

A. I have submitted studies or testified on cost of capital and other financial issues before the Interstate Commerce Commission, Bonneville Power Administration, and courts or regulatory agencies in fifteen states.

My studies and testimony have included consideration of the financial health and fair rates of return for Portland General Electric, General Telephone of the Northwest, Illinois Bell Telephone, Nevada Bell Telephone, Pacific Northwest Bell, U S WEST, Alaska Electric Light and Power, Alaska Power Company, Anchorage Municipal Light & Power, Arizona Public Service, Bear Valley Electric Service, Black Bear Lake Hydro, Inc., Commonwealth Edison, Idaho Power, Iowa-Illinois Gas and Electric, Pacific Power & Light, Puget Sound Power & Light, Cascade Natural Gas, Mountain Fuel Supply, Northern Illinois Gas, Northwest Natural Gas, Anchorage Water Utility, Anchorage Wastewater Utility, Arizona Water Company, Arizona-American Water Company, California-American Water Company, California Water Service, Chaparral City Water Company, Dominguez Water Company, Golden State Water Company, Hawaii-American Water Company, Kentucky-American Water Company, Mountain Water Company, New Mexico-American Water Company, New Mexico Utilities, Inc., Oregon Water Company, Paradise Valley Water Company, Park Water Company, San Gabriel Valley Water Company, San Jose Water Company, Southern California Water Company, Suburban Water System, Tennessee-American Water Company, and Valencia Water Company. I also prepared estimates of the appropriate rates of return for a number of hospitals in Washington, a large insurance company, and U.S. railroads.

Q. Do you have other professional experience related to cost of capital issues?

A. Yes. My article, "Utility Stocks and the Size Effect - Revisited," was published in the *Quarterly Review of Economics and Finance*, Vol. 43, Issue 3, Autumn 2003, pp. 578-582. Also, I published an article "Water Utilities and Risk," *Water the Magazine of the National Association of Water Companies* Vol. 40, No. 1 Winter 1999 and was an invited speaker on the topic of risk of water utilities at the 57th Annual Western Conference of Public Utility Commissioners in June 1998. I presented a paper "Application of the Capital Asset Pricing Model in the Regulatory Setting" at the 47th Annual Southern Economic Association Conference and published an article "On the Use of the CAPM in Public Utility Rate Cases: Comment," *Financial Management* Autumn 1978, pp. 52-56. I have been a journal referee for the *International Review of Economics and Finance* and *Financial Management.* While on the staff of the Oregon PUC, I also established a sample of over 500,000 observations of common stock returns and measures of risk and conducted a number of studies related to the use of various methods to estimate costs of equity for utilities. I was invited to Stanford University to discuss that research.

Q. Does this conclude your prefiled testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
1201	Comparison of PGE to the DCF Electric Utilities Sample
1202	Past, Current, and Forecasted Bond Rates
1203	DCF Risk Premium (Value Line Composite)
1204	California DRA Relative Risk Analysis
1205	Size Premium
1206	Electric Utility Sample Dividend Yield
1207	EPS Growth Forecast
1208	Constant Growth DCF Estimates
1209	Two-Stage DCF Estimates
1210	Three-Stage DCF Estimates
1211	2014-2015 Bond Rate Forecasts
1212	California DRA Risk Premium Analysis
1213	Holding Period Return Risk Premium Analysis
1214	Authorized ROE & Treasury Risk Premium Analysis
1215	Earned, Authorized, and Forecasted ROEs
1216	Summary of ROE Analyses

Portland General Electric

PGE Exhibit 1201 (page 1)

Comparison of PGE to the DCF Electric Utilities Sample

			Value Line Betas[c/]	S&P Business Risk Profile	Financial Risk Profile	S&P Bond Rating[a,b/]	Moody's Bond Rating[a,b/]
1	ALLETE	ALE	0.70	Strong	Significant	A-	A2
2	Alliant Energy	LNT	0.70	Excellent	Significant	BBB+	A2/A3
3	Avista	AVA	0.70	Excellent	Aggressive	A-	A3
4	Black Hills Corporation	BKH	0.80	Excellent	Aggressive	BBB+	A3
5	CLECO Corporation	CNL	0.65	Excellent	Aggressive	BBB	Baa2
6	CMS Energy	CMS	0.75	Excellent	Aggressive	BBB/BBB-	Baa2
7	Empire District Electric	EDE	0.65	Excellent	Aggressive	BBB+	A3
8	Hawaiian Electric	HE	0.70	Strong	Aggressive	BBB-	Baa2
9	IDACORP	IDA	0.70	Excellent	Aggressive	A-	A2
10	MGE Energy, Inc.	MGEE	0.60	Excellent	Intermediate	AA-	A1
11	Northwestern Corp	NWE	0.70	Excellent	Aggressive	A-	A2
12	NV Energy	NVE	0.85	Excellent	Highly Leveraged	BBB	Baa1
13	OGE Energy	OGE	0.75	Strong	Significant	BBB	Baa1
14	Pinnacle West	PNW	0.70	Excellent	Significant	BBB	Baa1
15	Portland General Electric	POR	0.75	Excellent	Aggressive	A-	A3
16	SCANA	SCG	0.65	Excellent	Aggressive	BBB+	Baa1/Baa2
17	TECO	TE	0.85	Excellent	Significant	BBB+	A3
18	UNS Energy	UNS	0.70	Strong	Aggressive	BBB-	Baa2
19	Westar	WR	0.75	Excellent	Aggressive	BBB+	A3
20	Wisconsin Energy	WEC	0.65	Excellent	Significant	A-/BBB+	A2/A3
	Average		0.72			BBB+	A3
	PGE		0.75	Excellent	Aggressive	A-	A3

Notes and Sources

a/ AUS Utility Reports, November 2012.
b/ Northwestern bond rating per SEC Form 10-K.
c/ Value Line Investment Survey Issue 1 (dated November 23, 2012), Issue 5 (dated September 21, 2012) and Issue 11 (dated November 2, 2012).

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Portland General Electric

PGE Exhibit 1201 (page 2)

Comparison of PGE to the DCF Electric Utilities Sample

		Percentage of Electric Revenues[a/]	Expected Common Equity Ratio[c/]	Market Capitalization[a,e/] ($ millions)	Decoupling Available in at Least One State[f/]	Percentage of Purchased Power[c/]
1	ALLETE	90%	56%	$1,611	yes	35%
2	Alliant Energy	77%	51%	$5,021	yes	na
3	Avista	61%	48%	$1,567	yes	44%
4	Black Hills Corporation	52%	49%	$1,595	yes[g/]	62%
5	CLECO Corporation	94%	58%	$2,549	no	14%
6	CMS Energy	63%	40%	$6,374	yes	52%
7	Empire District Electric	92%	51%	$930	yes[g/]	30%
8	Hawaiian Electric	92%	54%	$2,568	yes	40%
9	IDACORP	100%	53%	$2,247	yes	14%
10	MGE Energy, Inc.	73%	66%	$1,245	yes	38%
11	Northwestern Corp	75%	51%	$1,486	yes[g/]	na
12	NV Energy	96%	49%	$4,458	yes[g/]	36%
13	OGE Energy	57%	49%	$5,655	yes[g/]	16%
14	Pinnacle West	100%	58%	$5,901	yes[g/]	19%
15	Portland General Electric	100%	54%	$2,113	yes	56%
16	SCANA	58%	47%	$6,470	no	1%
17	TECO	63%	43%	$3,890	no	6%
18	UNS Energy	85%	28%	$1,744	yes[g/]	0%
19	Westar	100%	50%	$3,797	no	0%
20	Wisconsin Energy	75%	47%	$8,946	yes	37%
	Average	80%	50%	$3,508		28%
	Portland General Electric	100%	54%	$2,113	yes	56%

Notes and Sources (continued)

d/ Average equity ratio is the median.
e/ Market Capitalization as of October 17, 2012.
f/ Source: IEE, State Energy Efficiency Regulatory Frameworks, Summary Table, July 2012.
g/ Fixed cost recovery provided by a Lost Revenue Adjustment Mechanism instead of decoupling.

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Portland General Electric

PGE Exhibit 1202

**Past, Current and Forecasted Rates for
Treasury Securities , Aaa Bonds and Baaa Bonds**

A. Past Actual Rates (1980 to 2011)–[a/]

Year	30-Year Treasury Rates	Aaa Rates	Baa Rates
1980	11.27%	11.94%	13.67%
1981	13.45%	14.17%	16.04%
1982	12.76%	13.79%	16.11%
1983	11.18%	12.04%	13.55%
1984	12.41%	12.71%	14.19%
1985	10.79%	11.37%	12.72%
1986	7.78%	9.02%	10.39%
1987	8.59%	9.38%	10.58%
1988	8.96%	9.71%	10.83%
1989	8.45%	9.26%	10.18%
1990	8.61%	9.32%	10.36%
1991	8.14%	8.77%	9.80%
1992	7.67%	8.14%	8.98%
1993	6.59%	7.22%	7.93%
1994	7.37%	7.97%	8.63%
1995	6.88%	7.59%	8.20%
1996	6.71%	7.37%	8.05%
1997	6.61%	7.27%	7.87%
1998	5.58%	6.53%	7.22%
1999	5.87%	7.05%	7.88%
2000	5.94%	7.62%	8.37%
2001	5.49%	7.08%	7.95%
2002	5.43%	6.49%	7.80%
2003	5.05%	5.66%	6.76%
2004	5.12%	5.63%	6.39%
2005	4.56%	5.23%	6.06%
2006	4.91%	5.59%	6.48%
2007	4.84%	5.56%	6.48%
2008	4.28%	5.63%	7.44%
2009	4.08%	5.31%	7.29%
2010	4.25%	4.94%	6.04%
2011	3.91%	4.64%	5.66%
Average	7.30%	8.13%	9.25%
B. Current rates–[b/]	2.72%	3.49%	4.48%
C. Expected rates–[c/]	4.19%	4.94%	5.76%

Notes and Sources:
a/ Source is Federal Reserve or as implied by rates for 20-year Treasury bonds when 30-year bonds are not available.
b/ As reported by the Federal Reserve for November 15, 2012.
c/ Averages of rates expected in 2014 to 2015. See PGE Exhibit 1211.

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Portland General Electric

PGE Exhibit 1203

Determination of Average Risk Premiums Based on DCF Analyses of the Value Line Industrial Composite: 1984 to 2012

	Study Date	Dividend Yield	Average of Forecasted EPS and BR Growth	DCF Equity Cost	Long-term Treasury Lag 1 Month	Risk Premium
1	1/84	4.00%	9.29%	13.29%	11.88%	1.41%
2	1/85	3.80%	12.06%	15.86%	11.52%	4.34%
3	1/86	3.80%	10.11%	13.91%	9.54%	4.37%
4	2/87	3.00%	9.45%	12.45%	7.39%	5.06%
5	2/88	3.10%	11.24%	14.34%	8.83%	5.51%
6	7/88	3.50%	8.28%	11.78%	9.00%	2.78%
7	2/89	3.50%	10.03%	13.53%	8.93%	4.60%
8	2/90	3.20%	7.89%	11.09%	8.26%	2.83%
9	1/91	3.70%	9.03%	12.73%	8.24%	4.49%
10	2/92	2.80%	10.02%	12.82%	7.58%	5.24%
11	2/93	2.90%	7.64%	10.54%	7.34%	3.20%
12	2/94	3.00%	10.84%	13.84%	6.39%	7.45%
13	2/95	2.70%	11.19%	13.89%	7.97%	5.92%
14	3/96	2.70%	12.49%	15.19%	6.03%	9.16%
15	2/97	2.40%	11.92%	14.32%	6.91%	7.41%
16	1/98	1.50%	12.79%	14.29%	6.07%	8.22%
17	1/99	1.30%	13.63%	14.93%	5.36%	9.57%
18	2/00	0.80%	12.38%	13.18%	6.86%	6.32%
19	7/00	1.00%	12.30%	13.30%	6.28%	7.02%
20	2/01	1.20%	10.60%	11.80%	5.65%	6.15%
21	7/01	1.20%	10.00%	11.20%	5.82%	5.38%
22	1/02	1.20%	8.89%	10.09%	5.76%	4.33%
23	8/02	1.60%	7.68%	9.28%	5.51%	3.77%
24	1/03	1.60%	7.26%	8.86%	5.01%	3.85%
25	7/03	1.50%	9.79%	11.29%	4.34%	6.95%
26	3/04	1.60%	9.05%	10.65%	4.94%	5.71%
27	10/04	1.80%	9.35%	11.15%	4.89%	6.26%
28	4/05	1.90%	8.74%	10.64%	4.89%	5.75%
29	11/05	2.10%	10.88%	12.98%	4.74%	8.24%
30	5/06	2.10%	9.12%	11.22%	5.22%	6.00%
31	11/06	2.20%	11.77%	13.97%	4.94%	9.03%
32	5/07	2.50%	10.87%	13.37%	4.87%	8.50%
33	11/07	1.60%	11.70%	13.30%	4.77%	8.53%
34	5/08	1.80%	13.69%	15.49%	4.44%	11.05%
35	11/08	2.80%	11.68%	14.48%	4.17%	10.31%
36	5/09	2.80%	12.42%	15.22%	3.76%	11.46%
37	11/09	2.40%	10.86%	13.26%	4.19%	9.07%
38	8/10	2.00%	10.04%	12.04%	3.99%	8.05%
39	3/11	1.60%	9.89%	11.49%	4.65%	6.84%
40	11/11	2.00%	9.25%	11.25%	3.13%	8.12%
41	6/12	2.10%	8.77%	10.87%	2.93%	7.94%

Averages for:	
All years (1987-2012)	6.5%
Last 4 years (2009-2012)	8.6%

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Portland General Electric

PGE Exhibit 1204 (page 1)

California DRA Relative Risk Analysis Applied to PGE

Electric Utilities[a/]		2007	2008	2009	2010	2011	5-Year Average	TEST #1 Average Over (Under) Performance	Standard Deviation	TEST #2 Coeff. Of Variation
1 ALLETE, Inc.	Eamed ROE	11.80%	10.00%	6.60%	7.70%	8.70%	8.96%	-1.98%	2.02%	0.23
	Authorized ROE	11.60%	11.60%	10.74%	10.38%	10.38%	10.94%			
2 Alliant Energy Corporation	Eamed ROE	11.30%	9.30%	6.80%	9.90%	10.10%	9.48%	-1.28%	1.66%	0.18
	Authorized ROE	11.02%	11.02%	11.02%	10.41%	10.34%	10.76%			
3 Avista Corporation	Eamed ROE	4.20%	7.40%	8.30%	8.20%	8.50%	7.32%	-3.02%	1.79%	0.25
	Authorized ROE	10.40%	10.25%	10.40%	10.33%	10.33%	10.34%			
4 Black Hills	Eamed ROE	10.30%	0.70%	8.30%	5.90%	3.30%	5.70%	-5.01%	3.83%	0.67
	Authorized ROE	na	10.75%	10.71%	10.64%	10.72%	10.71%			
5 Cleco Corporation	Eamed ROE	7.80%	9.60%	9.50%	10.60%	11.10%	9.72%	-1.20%	1.27%	0.13
	Authorized ROE	11.25%	11.25%	10.70%	10.70%	10.70%	10.92%			
6 CMS Energy Corporation	Eamed ROE	7.20%	11.70%	8.50%	12.50%	12.60%	10.50%	-0.33%	2.49%	0.24
	Authorized ROE	11.08%	10.93%	10.93%	10.63%	10.60%	10.83%			
7 Empire District Electric Co.	Eamed ROE	6.20%	7.50%	6.90%	7.20%	7.90%	7.14%	-3.68%	0.64%	0.09
	Authorized ROE	10.90%	10.80%	10.80%	10.80%	10.80%	10.82%			
8 Hawaiian Electric Industries	Eamed ROE	7.20%	6.50%	5.80%	7.70%	9.00%	6.80%	-4.09%	1.22%	0.18
	Authorized ROE	11.22%	10.82%	10.82%	10.70%	10.47%	10.89%			
9 IDACORP	Eamed ROE	6.80%	7.60%	8.90%	9.30%	10.10%	8.15%	-2.21%	1.33%	0.16
	Authorized ROE	10.25%	10.50%	10.50%	10.18%	10.18%	10.36%			
10 MGE Energy, Inc.	Eamed ROE	11.40%	11.00%	10.20%	11.00%	11.10%	10.94%	0.28%	0.44%	0.04
	Authorized ROE	11.00%	10.80%	10.80%	10.40%	10.30%	10.66%			
11 Northwestern Corporation	Eamed ROE	6.50%	8.90%	9.30%	9.40%	10.80%	8.98%	-2.16%	1.56%	0.17
	Authorized ROE	11.46%	11.11%	11.11%	11.11%	10.90%	11.14%			
12 NV Energy	Eamed ROE	6.60%	6.70%	5.70%	6.80%	4.80%	6.12%	-4.46%	0.86%	0.14
	Authorized ROE	10.48%	10.48%	10.67%	10.67%	10.58%	10.58%			
13 OGE Energy Corp.	Eamed ROE	14.50%	12.20%	12.70%	12.90%	13.40%	13.08%	2.82%	0.87%	0.07
	Authorized ROE	10.38%	10.38%	10.13%	10.13%	9.98%	10.26%			
14 Pinnacle West Capital Corp.	Eamed ROE	8.50%	6.20%	6.90%	9.00%	8.60%	7.65%	-3.16%	1.22%	0.16
	Authorized ROE	10.75%	10.75%	10.75%	11.00%	11.00%	10.81%			

Portland General Electric

PGE Exhibit 1204 (page 2)

California DRA Relative Risk Analysis Applied to PGE

Electric Utilities (continued)-[a/]		2007	2008	2009	2010	2011	5-Year Average	TEST #1 Average Over (Under) Performance	Standard Deviation	TEST #2 Coeff. Of Variation
15 Portland General Electric		Not included in sample averages					** **	**	**	**
16 SCANA	Earned ROE	10.80%	11.40%	10.20%	10.20%	10.00%	10.52%	-0.17%	0.58%	0.05
	Authorized ROE	10.71%	10.67%	10.67%	10.67%	10.72%	10.69%			
17 TECO Energy, Inc.	Earned ROE	13.20%	8.10%	10.30%	11.20%	12.00%	10.96%	-0.14%	1.92%	0.18
	Authorized ROE	11.25%	11.25%	11.00%	11.00%	11.00%	11.10%			
18 UNS Energy	Earned ROE	8.50%	2.10%	13.90%	13.60%	12.40%	10.10%	-0.08%	4.96%	0.49
	Authorized ROE	10.67%	10.34%	10.13%	9.88%	9.88%	10.18%			
19 Westar Energy, Inc.	Earned ROE	9.20%	6.20%	6.30%	8.50%	7.70%	7.58%	-2.50%	1.33%	0.17
	Authorized ROE	10.00%	10.00%	10.00%	10.20%	10.20%	10.08%			
20 Wisconsin Energy	Earned ROE	10.90%	10.70%	10.60%	12.00%	12.90%	11.42%	0.73%	1.00%	0.09
	Authorized ROE	11.20%	10.75%	10.75%	10.38%	10.38%	10.69%			
				Average Earned ROE			9.01%			
				Average Authorized ROE			10.67%			
				Average for Test				-1.67%	1.63%	0.19

		2007	2008	2009	2010	2011	5-Year Average	TEST #1		TEST #2
Portland General Electric	Earned ROE	11.00%	6.40%	6.20%	7.90%	8.80%	7.88%	-2.20%	1.96%	0.25
	Authorized ROE	10.10%	10.10%	10.00%	10.10%	10.00%	10.08%			

Notes and Sources:
a/ Utilities in electric utilities sample. Earned ROEs from Value Line.
Authorized ROEs reported by AUS Utilities Reports or Value Line.
If authorized ROE not reported for a particular year, the previously authorized ROE is adopted.

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Portland General Electric

PGE Exhibit 1205

Evidence Showing Risk Increases as the Size of Companies Decrease

		Beta Risk	Size Risk Premium
1.	Evidence from Morningstar–[a]		
	Mid-Cap Companies–[b]	1.13	1.06%
	Low-Cap Companies–[c]	1.26	1.67%
	Micro-Cap Companies–[d]	1.51	2.90%
2.	Evidence Published in Zepp Article–[e]		0.99%

Notes and Sources:
a/ Data from Table 7-12 of Morningstar 2012 SBBI Valuation Edition Yearbook.
b/ Companies with market capitalization between $1,620 million and $6,896 million included in the Morningstar 2012 study.
c/ Companies with market capitalization between $423 million and $1,620 million. included in the Morningstar 2012 study.
d/ Companies with market capitalization less than $423 million included in study.
e/ From Table 2 in T.M. Zepp, "Utility Stocks and the Size Effect--Revisited," *The Quarterly Review of Economics and Finance*, 43 (2003), 578-582.

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Portland General Electric

PGE Exhibit 1206

Average Expected Dividend Yields (D_1/P_0) for Utilities in the Electric Utilities Sample

		3-Month Average[a]
1	ALLETE	4.87%
2	Alliant Energy	4.49%
3	Avista	5.05%
4	Black Hills Corporation	4.44%
5	CLECO Corporation	3.55%
6	CMS Energy	4.51%
7	Empire District Electric	5.00%
8	Hawaiian Electric	5.04%
9	IDACORP	3.69%
10	MGE Energy, Inc.	3.28%
11	Northwestern Corp	4.48%
12	NV Energy	4.19%
13	OGE Energy	3.03%
14	Pinnacle West	4.44%
15	Portland General Electric	4.36%
16	SCANA	4.44%
17	TECO	5.34%
18	UNS Energy	4.45%
19	Westar	4.91%
20	Wisconsin Energy	3.77%
	Average	4.40%

Source:
_a/ For the period ending November 30, 2012. To reduce controversy, adopts Value Line forecasts of D_1.

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Portland General Electric

PGE Exhibit 1207

Estimates of Growth Based on Value Line and Analysts' Forecasts of EPS Growth

		Value Line[a/]	Analysts' Forecasts of Growth				Average of Analysts' Forecasts and Value Line Forecasts
			Yahoo![b/]	Zacks[b/]	Reuters[b/]	Average	
		(a)	(b)	(c)	(d)	(e)	(f)
1	ALLETE	9.0	6.0	5.5	7.0	6.2	7.6
2	Alliant Energy	6.5	4.8	6.1	5.5	5.5	6.0
3	Avista	3.5	4.0	4.3	4.5	4.3	3.9
4	Black Hills Corporation	7.0	6.0	6.0	na	6.0	6.5
5	CLECO Corporation	6.5	3.0	3.0	3.0	3.0	4.8
6	CMS Energy	7.0	6.3	6.0	6.3	6.2	6.6
7	Empire District Electric	6.0	10.2	na	na	10.2	8.1
8	Hawaiian Electric	9.0	8.1	7.0	6.1	7.1	8.0
9	IDACORP	2.0	4.0	4.0	4.0	4.0	3.0
10	MGE Energy, Inc.	5.0	4.0	4.0	4.0	4.0	4.5
11	Northwestern Corp	3.5	6.7	5.3	7.0	6.3	4.9
12	NV Energy	11.0	2.9	15.1	3.9	7.3	9.1
13	OGE Energy	4.5	5.4	5.4	5.3	5.4	4.9
14	Pinnacle West	5.0	5.1	6.0	5.1	5.4	5.2
15	Portland General Electric	5.5	2.7	4.1	4.0	3.6	4.5
16	SCANA	4.0	5.0	4.8	5.0	5.0	4.5
17	TECO	5.5	3.3	1.8	4.4	3.2	4.3
18	UNS Energy	5.5	8.0	6.3	2.7	5.7	5.6
19	Westar	6.5	5.9	5.7	6.1	5.9	6.2
20	Wisconsin Energy	6.5	5.7	5.4	6.9	6.0	6.2
	Average	6.0				5.5	5.7

Notes and Sources:

a/ Value Line Investment Survey Issue 1 (dated November 23, 2012), Issue 5 (dated September 21, 2012) and Issue 11 (dated August 3, 2012).

b/ Sources are analysts' forecasts reported on the Internet on November 13, 2012.

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Portland General Electric

PGE Exhibit 1208

Constant Growth DCF Cost of Equity Estimates

		3-Month Average D_1/P_0 [a,b]	Average of Forecasts of Growth [c]	Equity Cost Estimates
1	ALLETE	4.87%	7.58%	12.5%
2	Alliant Energy	4.49%	5.99%	10.5%
3	Avista	5.05%	3.88%	8.9%
4	Black Hills Corporation	4.44%	6.50%	10.9%
5	CLECO Corporation	3.55%	4.75%	8.3%
6	CMS Energy	4.51%	6.60%	11.1%
7	Empire District Electric	5.00%	8.10%	13.1%
8	Hawaiian Electric	5.04%	8.03%	13.1%
9	IDACORP	3.69%	3.00%	6.7%
10	MGE Energy, Inc.	3.28%	4.50%	7.8%
11	Northwestern Corp	4.48%	4.91%	9.4%
12	NV Energy	4.19%	9.14%	13.3%
13	OGE Energy	3.03%	4.93%	8.0%
14	Pinnacle West	4.44%	5.19%	9.6%
15	Portland General Electric	4.36%	4.55%	8.9%
16	SCANA	4.44%	4.48%	8.9%
17	TECO	5.34%	4.34%	9.7%
18	UNS Energy	4.45%	5.58%	10.0%
19	Westar	4.91%	6.20%	11.1%
20	Wisconsin Energy	3.77%	6.24%	10.0%
	Average			10.1%

Notes and Sources:

a/ The 3-month average yields reported in Table 6. Yields are adjusted for time value of money.

b/ Per OPUC method, D_1 is based on Value Line forecasts for 2013.

c/ Average of Value Line and analysts' forecasts reported in PGE Exhibit 1207.

d/ ROE = $D_1/P_0 + g$

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Portland General Electric

PGE Exhibit 1209

Application of the FERC Two-Stage Multiperiod DCF Method

			Low Estimate		High Estimate	
		D_1/P_0	Low Growth	Low Equity Cost Estimate	High Growth	High Equity Cost Estimate
1	ALLETE	4.87%	5.67%	10.53%	8.01%	12.88%
2	Alliant Energy	4.49%	5.20%	9.69%	6.34%	10.83%
3	Avista	5.05%	4.33%	9.38%	5.00%	10.05%
4	Black Hills Corporation	4.44%	6.00%	10.44%	6.67%	11.11%
5	CLECO Corporation	3.55%	3.99%	7.54%	6.34%	9.88%
6	CMS Energy	4.51%	6.00%	10.51%	6.67%	11.18%
7	Empire District Electric	5.00%	6.00%	11.00%	8.81%	13.81%
8	Hawaiian Electric	5.04%	6.03%	11.07%	8.01%	13.05%
9	IDACORP	3.69%	3.32%	7.01%	4.66%	8.35%
10	MGE Energy, Inc.	3.28%	4.66%	7.94%	5.33%	8.61%
11	Northwestern Corp	4.48%	4.33%	8.81%	6.67%	11.15%
12	NV Energy	4.19%	3.89%	8.08%	12.10%	16.29%
13	OGE Energy	3.03%	5.00%	8.03%	5.60%	8.63%
14	Pinnacle West	4.44%	5.33%	9.77%	6.00%	10.44%
15	Portland General Electric	4.36%	3.77%	8.13%	5.67%	10.03%
16	SCANA	4.44%	4.66%	9.10%	5.35%	9.79%
17	TECO	5.34%	3.19%	8.53%	5.67%	11.01%
18	UNS Energy	4.45%	3.76%	8.21%	7.34%	11.79%
19	Westar	4.91%	5.80%	10.71%	6.34%	11.24%
20	Wisconsin Energy	3.77%	5.60%	9.37%	6.58%	10.34%
	Average				10.1%	

Sources and Notes:

a/ Use FERC method of assigning a weight of two-thirds to average EPS growth rates reported in PGE Exhibit 1207 and one-third to a forecast of future GDP growth of 6.0%.

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Portland General Electric

PGE Exhibit 1210

Three Stage DCF Analysis

		Internal Rate of Return		First Year Dividend D_1 [a/]	Stage 1 [b/]		Stage 2 and 3 [c,d/]				
		Return	P_{2012}	D_{2013}	D_{2014}	D_{2018}	D_{2019}	D_{2020}	D_{2027}	$(P+D)_{2028}$	P_{2028} [d/]
1	ALLETE	11.4%	-$40.20	$1.95	$2.10	$2.81	$3.02	$3.24	$5.07	$110.84	$105.46
2	Alliant Energy	10.5%	-$43.94	$1.97	$2.09	$2.63	$2.79	$2.96	$4.45	$116.30	$111.59
3	Avista	10.3%	-$24.78	$1.24	$1.29	$1.51	$1.57	$1.63	$2.32	$62.99	$60.53
4	Black Hills Corporation	10.6%	-$35.07	$1.56	$1.66	$2.13	$2.27	$2.41	$3.68	$93.79	$89.89
5	CLECO Corporation	9.2%	-$41.11	$1.45	$1.52	$1.83	$1.92	$2.02	$2.93	$106.01	$102.90
6	CMS Energy	10.7%	-$23.51	$1.06	$1.13	$1.46	$1.55	$1.65	$2.52	$63.00	$60.33
7	Empire District Electric	11.7%	-$20.82	$1.04	$1.12	$1.53	$1.65	$1.78	$2.83	$58.27	$55.28
8	Hawaiian Electric	11.7%	-$25.68	$1.29	$1.39	$1.89	$2.04	$2.19	$3.48	$71.82	$68.13
9	IDACORP	8.9%	-$42.93	$1.58	$1.62	$1.83	$1.89	$1.96	$2.71	$106.68	$103.81
10	MGE Energy, Inc.	8.9%	-$51.65	$1.68	$1.76	$2.09	$2.19	$2.30	$3.32	$131.50	$127.98
11	Northwestem Corp	10.1%	-$35.32	$1.58	$1.65	$2.00	$2.10	$2.21	$3.23	$91.48	$88.05
12	NV Energy	11.2%	-$18.34	$0.77	$0.84	$1.19	$1.29	$1.40	$2.29	$51.87	$49.44
13	OGE Energy	8.7%	-$56.94	$1.72	$1.81	$2.19	$2.30	$2.42	$3.53	$144.82	$141.07
14	Pinnacle West	10.2%	-$51.47	$2.28	$2.40	$2.94	$3.09	$3.26	$4.79	$133.97	$128.89
15	Portland General Electric	9.9%	-$26.47	$1.15	$1.20	$1.44	$1.50	$1.58	$2.28	$68.03	$65.61
16	SCANA	10.0%	-$47.29	$2.09	$2.19	$2.61	$2.73	$2.86	$4.13	$121.45	$117.07
17	TECO	10.7%	-$17.13	$0.91	$0.95	$1.13	$1.18	$1.23	$1.78	$43.99	$42.11
18	UNS Energy	10.3%	-$41.07	$1.82	$1.93	$2.39	$2.53	$2.67	$3.97	$107.75	$103.54
19	Westar	11.0%	-$28.81	$1.41	$1.50	$1.90	$2.02	$2.15	$3.24	$76.92	$73.48
20	Wisconsin Energy	9.8%	-$37.47	$1.41	$1.50	$1.91	$2.03	$2.15	$3.26	$99.03	$95.57
	Average	10.3%									

Notes and Sources:

a/ Value Line forecast of DPS for 2013 adjusted for the time value of money. See PGE Exhibit 1206.
b/ Average of Value Line forecasts and analysts' forecasts from PGE Exhibit 1207.
c/ Growth based on gradual transition from initial forecasts of EPS growth to expected long-term average GDP growth of 6.0%.
d/ Price received at end of stage 2.

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Portland General Electric

PGE Exhibit 1211

Forecasts of Baa, Aaa and Long-term Treasury Securities Rates 2014 - 2015

	2014	2015	Average
Long-term Treasury Rates			
Blue Chip Consensus Forecasts[a/]	3.60%	4.30%	3.95%
Value Line[b/]	4.50%	4.70%	4.60%
Global Insight[c/]	3.84%	4.19%	4.02%
Overall Average			4.19%
Aaa Corporate Bonds			
Blue Chip Consensus Forecasts[a/]	4.30%	5.00%	4.65%
Value Line[b/]	5.20%	5.50%	5.35%
Global Insight[c/]	4.53%	5.11%	4.82%
Overall Average			4.94%
Baa Corporate Bonds			
Blue Chip Consensus Forecasts[a/]	5.30%	5.90%	5.60%
Global Insight[c/]	5.65%	6.19%	5.92%
Overall Average			5.76%

Sources and Notes:
a/ Blue Chip consensus forecasts published December 1, 2012.
b/ Value Line Quarterly forecasts dated November 23, 2012.
c/ IHS Global Insight, November, 2012.

Portland General Electric

PGE Exhibit 1212

Risk Premium Analysis: Proxies for Costs of Equity are Based on Method Used by California PUC Department of Ratepayer Advocates–[a/]
1997 to 2011

	Return on Equity–[b/]	Long-term Treasury Bond Rates–[c/]	Average Annual Risk Premiums
1997	10.40%	6.61%	3.79%
1998	10.90%	5.58%	5.32%
1999	12.20%	5.87%	6.33%
2000	7.00%	5.94%	1.06%
2001	12.30%	5.49%	6.81%
2002	9.80%	5.42%	4.38%
2003	10.50%	5.05%	5.45%
2004	11.10%	5.12%	5.98%
2005	11.60%	4.56%	7.04%
2006	11.30%	4.91%	6.39%
2007	12.10%	4.84%	7.26%
2008	11.80%	4.28%	7.52%
2009	10.60%	4.08%	6.52%
2010	11.00%	4.25%	6.75%
2011	10.50%	3.91%	6.59%
	15-Year Average	5.06%	5.81%
	5-year Average	4.27%	6.93%
	Expected Long-term Treasury Bond Rate–[d/]		4.19%
	Projected Returns on Equity for Sample		
	15-Year Average		10.0%
	5-Year Average		11.1%

Notes and Sources:

a/ Method developed in Division of Ratepayer Advocates, CPUC, *Report on the Cost of Capital for San Jose Water,* June 2006, A.06-02-014, Table 2-7. Proxies for costs of equity are averages of earned returns on equity.

b/ Composite of average earned ROEs for electric utilities reported in various issues of Value Line Investment Survey, from 1997 to 2012. ROEs are not adjusted upward to put ROEs on a mid-period basis.

c/ As reported by the Federal Reserve or California DRA Staff.

d/ Source is PGE Exhibit 1211.

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Portland General Electric

PGE Exhibit 1213: Risk Premium Analysis Based on Holding Period Returns for Moody's Electric Utilities Sample as Updated, 1950 to 2011

	Long-term Treasury Bond Rate[a/]	Year-end Price Index[b/]	Annual Average Dividend[b/]	Index Gain/Loss	Dividend Yield	Total Return	Risk Premium
1950	2.24%	$30.81					
1951	2.69%	$33.85	$1.88	9.87%	6.10%	15.97%	13.73%
1952	2.79%	$37.85	$1.91	11.82%	5.64%	17.46%	14.77%
1953	2.74%	$39.61	$2.01	4.65%	5.31%	9.96%	7.17%
1954	2.72%	$47.56	$2.13	20.07%	5.38%	25.45%	22.71%
1955	2.95%	$49.35	$2.21	3.76%	4.65%	8.41%	5.69%
1956	3.45%	$48.96	$2.32	-0.79%	4.70%	3.91%	0.96%
1957	3.23%	$50.30	$2.43	2.74%	4.96%	7.70%	4.25%
1958	3.82%	$66.37	$2.50	31.95%	4.97%	36.92%	33.69%
1959	4.47%	$65.77	$2.61	-0.90%	3.93%	3.03%	-0.79%
1960	3.80%	$76.82	$2.68	16.80%	4.07%	20.88%	16.41%
1961	4.15%	$99.32	$2.81	29.29%	3.66%	32.95%	29.15%
1962	3.95%	$96.49	$2.97	-2.85%	2.99%	0.14%	-4.01%
1963	4.17%	$102.31	$3.21	6.03%	3.33%	9.36%	5.41%
1964	4.23%	$115.54	$3.43	12.93%	3.35%	16.28%	12.11%
1965	4.50%	$114.86	$3.86	-0.59%	3.34%	2.75%	-1.48%
1966	4.55%	$105.99	$4.11	-7.72%	3.58%	-4.14%	-8.64%
1967	5.56%	$98.19	$4.34	-7.36%	4.09%	-3.26%	-7.81%
1968	5.98%	$104.04	$4.50	5.96%	4.58%	10.54%	4.98%
1969	6.87%	$84.62	$4.61	-18.67%	4.43%	-14.23%	-20.21%
1970	6.48%	$88.59	$4.70	4.69%	5.55%	10.25%	3.38%
1971	5.97%	$85.56	$4.77	-3.42%	5.38%	1.96%	-4.52%
1972	5.99%	$83.61	$4.87	-2.28%	5.69%	3.41%	-2.56%
1973	7.26%	$60.87	$5.01	-27.20%	5.99%	-21.21%	-27.20%
1974	7.60%	$41.17	$4.83	-32.36%	7.93%	-24.43%	-31.69%
1975	8.05%	$55.66	$4.97	35.20%	12.07%	47.27%	39.67%
1976	7.21%	$66.29	$5.18	19.10%	9.31%	28.40%	20.35%
1977	8.03%	$68.19	$5.54	2.87%	8.36%	11.22%	4.01%
1978	8.98%	$59.75	$5.81	-12.38%	8.52%	-3.86%	-11.89%
1979	10.12%	$56.41	$6.22	-5.59%	10.41%	4.82%	-4.16%
1980	11.99%	$54.42	$6.58	-3.53%	11.66%	8.14%	-1.98%
1981	13.34%	$57.20	$6.99	5.11%	12.84%	17.95%	5.96%
1982	10.95%	$70.26	$7.43	22.83%	12.99%	35.82%	22.48%
1983	11.97%	$72.03	$7.87	2.52%	11.20%	13.72%	2.77%
1984	11.70%	$80.16	$8.26	11.29%	11.47%	22.75%	10.78%
1985	9.56%	$94.98	$8.61	18.49%	10.74%	29.23%	17.53%
1986	7.89%	$113.66	$8.89	19.67%	9.36%	29.03%	19.47%
1987	9.20%	$94.24	$9.12	-17.09%	8.02%	-9.06%	-16.95%
1988	9.18%	$100.94	$8.87	7.11%	9.41%	16.52%	7.32%
1989	8.16%	$122.52	$8.82	21.38%	8.74%	30.12%	20.94%
1990	8.44%	$117.77	$8.79	-3.88%	7.17%	3.30%	-4.86%
1991	7.30%	$144.02	$8.95	22.29%	7.60%	29.89%	21.45%
1992	7.26%	$141.06	$9.05	-2.06%	6.28%	4.23%	-3.07%
1993	6.54%	$146.70	$8.99	4.00%	6.37%	10.37%	3.11%
1994	7.99%	$115.50	$8.96	-21.27%	6.11%	-15.16%	-21.70%
1995	6.03%	$142.90	$9.02	23.72%	7.81%	31.53%	23.54%
1996	6.73%	$136.00	$9.06	-4.83%	6.34%	1.51%	-4.52%
1997	6.02%	$155.73	$9.06	14.51%	6.66%	21.17%	14.44%
1998	5.42%	$181.84	$7.83	16.77%	5.03%	21.79%	15.77%
1999	6.82%	$137.30	$8.10	-24.49%	4.45%	-20.04%	-25.46%
2000	5.58%	$227.09	$8.27	65.40%	6.02%	71.42%	64.60%
2001	5.75%	$210.70	$8.50	-7.22%	3.74%	-3.47%	-9.05%
2002	4.84%	$186.25	$8.80	-11.61%	4.18%	-7.43%	-13.18%
2003	5.11%	$229.73	$9.06	23.34%	4.87%	28.21%	23.37%
2004	4.84%	$264.61	$9.29	15.19%	4.04%	19.23%	14.12%
2005	4.61%	$270.56	$9.61	2.25%	3.63%	5.88%	1.04%
2006	4.91%	$311.69	$9.92	15.20%	3.66%	18.86%	14.25%
2007	4.50%	$285.03	$10.17	-8.55%	3.26%	-5.29%	-10.20%
2008	3.03%	$230.86	$10.42	-19.01%	3.65%	-15.35%	-19.85%
2009	4.58%	$259.53	$10.79	12.42%	4.67%	17.09%	14.06%
2010	4.14%	$308.96	$11.44	19.05%	4.41%	23.46%	18.88%
2011	2.48%	$330.91	$11.98	7.10%	3.88%	10.98%	6.84%

	Updated Study	Original Study
Average Treasury bond rate[a/]	6.21%	6.54%
Unadjusted risk premium	5.33%	5.70%
Expected Treasury bond rate[c/]	4.19%	4.19%
Adjusted risk premium[d/]	6.35%	6.88%
Estimated cost of equity for benchmark sample	10.5%	11.1%

Notes and Sources:

a/ Monthly rates for December of the indicated year. Morningstar, 2012 SBBI Valuation Yearbook, pages 184-185.

b/ Mergent, Moody's 2001 Public Utility Manual with updates for 2001-2010.

c/ Source is PGE Exhibit 1211.

d/ As explained in testimony, adjustment assumes equity costs change by 50% as much as interest rates.

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Portland General Electric

PGE Exhibit 1214

Risk Premiums Determined by Relationship Between Authorized ROEs and Long-term Treasury Bond Rates[a] During the Period 1984-2012

Formula: Risk Premium = A_0 + (A_1 x Treasury bond Rate)[c]

No. of Litigated Decisions	583
Std Err of Y Est	0.0078
R Squared	61.4%
Estimate of intercept (A_0)	0.0789
Estimate of slope (A_1)	-0.4252
Std Err of Coef.	0.0140
t-statistic for slope	-30.38

Equity Cost Estimate for Typical Electric Utility		Predicted Risk Premium		Expected Treasury Bond Rate[b]
10.3%	=	6.11%	+	4.19%

Sources and Notes:

_a/ Source of ROE Data: Oregon PUC Response to NW Natural Data request in UG 132 updated with data in Phillip Cross, "Rate of Return: Still an Issue at PUCs", *Public Utilities Fortnightly*, December 1998 and 2000 plus litigated decisions reported by Regulatory Research Associates and SNL for 1999-2012.

_b/ Average of forecasts for 2014 to 2015 reported in PGE Exhibit 1211.

_c/ 6-month lag between order dates and Treasury bond rates adopted.

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Portland General Electric

PGE Exhibit 1215

Earned, Authorized and Forecasted Returns on Common Equity

						Forecasted ROE Estimates		
		Earned ROEs[a]		Authorized ROEs[a]		Book Value Growth[c]	ROE Forecasted by Value Line[d]	Adjusted ROE Forecasts[e]
1	ALLETE	7.3%		10.4%		4.0%	10.5%	10.7%
2	Alliant Energy	10.0%		na		4.0%	11.0%	11.2%
3	Avista	7.7%	[b]	10.3%		3.0%	8.5%	8.6%
4	Black Hills Corporation	2.7%	[c]	10.7%		1.5%	8.0%	8.1%
5	CLECO Corporation	12.2%		10.7%		6.0%	11.5%	11.8%
6	CMS Energy	11.4%		10.3%		5.0%	12.5%	12.8%
7	Empire District Electric	8.0%		nm		2.5%	9.0%	9.1%
8	Hawaiian Electric	10.3%		10.0%		4.5%	10.0%	10.2%
9	IDACORP	10.8%		10.2%		4.0%	8.5%	8.7%
10	MGE Energy, Inc.	11.0%		10.3%		5.0%	11.0%	11.3%
11	Northwestern Corp	9.0%	[b]	10.3%	[b]	4.0%	10.0%	10.2%
12	NV Energy	6.8%		10.6%		3.5%	9.0%	9.2%
13	OGE Energy	13.8%		10.0%		7.0%	11.0%	11.4%
14	Pinnacle West	10.3%		11.0%		3.5%	9.0%	9.2%
15	Portland General Electric[f]							
16	SCANA	10.1%		10.7%		5.5%	9.5%	9.8%
17	TECO	11.8%		11.0%		4.5%	13.0%	13.3%
18	UNS Energy	10.7%		9.9%		3.0%	14.0%	14.2%
19	Westar Energy	9.3%		10.2%		5.0%	8.5%	8.7%
20	Wisconsin Energy	13.3%		10.3%		4.0%	13.5%	13.8%
	Average	10.2%		10.4%		4.2%	10.4%	10.6%
	Portland General Electric[f]	7.8%		10.0%		3.5%	9.0%	9.2%

Notes and Sources

a/ Except where noted, reported by AUS Utilities Reports in November 2012.
b/ If AUS data not available, data from Value Line is reported.
c/ Not included in average because it is below the cost of debt.
d/ Value Line Investment Survey Issue 1 (dated August 24, 2012), Issue 5 (dated September 21, 2012) and Issue 11 (dated November 2, 2012).
e/ ROE reported by Value Line is adjusted to a mid-period basis with method adopted by the FERC and California DRA Staff in Application 08-06-034. This method is Adjusted ROE = Reported ROE * 2*(1+g)/(2+g), where g is Value Line's forecast of book value per share growth for the respective utilities.
f/ Not included in averages

Portland General Electric

PGE Exhibit 1216

Summary: Estimated Costs of Equity

	Estimated Range of Costs of Equity for Electric Utilities Samples		
DCF Analyses			
Constant Growth Model - PGE Exhibit 1208		10.1%	
FERC Two-Step Model - PGE Exhibit 1209		10.1%	
Three Stage Model - PGE Exhibit 1210		10.3%	
Range of DCF estimates	10.1%	to	10.3%
Risk Premium Analyses			
California Staff Approach - PGE Exhibit 1212	10.0%	to	11.1%
Realized Annual Returns - PGE Exhibit 1213	10.5%	to	11.1%
Morin Statistical Approach -- PGE Exhibit 1214		10.3%	
Range of RP estimates	10.0%	to	11.1%
Range of Equity Cost Estimates[b/]	10.0%	to	10.7%
Range of Forecasted, Earned and Authorized ROEs	10.2%	to	10.6%

01/11/13

UE 262 / PGE / 1300
Nguyen - Dammen

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 262

Load Forecast

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Ham Nguyen
Sarah Dammen

February 15, 2013

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I. Introduction and Summary

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

A. My name is Ham T. Nguyen. I am employed by PGE as a Senior Economist. My name is Sarah J. Dammen. I am employed by PGE as an Economist. We are responsible for developing PGE's energy deliveries forecast. Our qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. This testimony presents and explains the methodology and processes underlying PGE's 2014 test year forecast of 19,233 million kilowatt-hours (kWh), on a cycle-month (billing) basis, delivered to customers, including deliveries to customers who opted out of PGE cost of service rates for direct access under Schedules 485 and 489.

Q. Please describe PGE's delivery forecast.

A. The 2014 forecast of total kWh deliveries takes into account the effect on demand of anticipated higher electricity prices in 2014 (compared to 2012 base period prices), and savings from "incremental" energy efficiency (EE) programs (funded through Schedule 109 Incremental Energy Efficiency Funding per Senate Bill (SB) 838).

There are three forecasts for the test year. They are B (base), P (price-effect), and E (post price-effect and "incremental" EE programs) forecasts. The B forecast considers the effect of economic activities on electricity delivery, all else equal. The P forecast incorporates the impact of higher electricity prices on delivery. The E forecast specifically accounts for the savings from incremental EE programs. PGE Exhibits 1301, 1302, and 1303 show the three detailed kWh delivery forecasts.

Q. How does the 2014 forecast compare to recent historical demand?

A. We forecast deliveries of 19,233 million kWh for test year 2014 on a cycle-month (billing) basis to all customers. The test year 2014 deliveries are down slightly from the 2012 weather adjusted actual deliveries of 19,289 million kWh.

Table 1 below summarizes the kWh delivery forecast in annual percentage changes by customer class from 2010 through 2014.

Table 1

Percent Change in kWh Delivery from Preceding Year: 2010-2014

Sector	2010	2011	2012	2013 (E)	2014 (E)
Residential	-2.5%	0.2%	0.4%	-0.2%	-0.5%
Commercial	-1.7%	-0.4%	0.2%	1.4%	0.4%
Industrial	1.4%	6.3%	1.4%	-10.5%	8.3%
Miscellaneous	-7.1%	0.7%	3.6%	5.7%	-1.9%
Total Retail	-1.4%	1.4%	0.6%	-2.0%	1.7%

Q. Why does PGE adjust the base forecast for price elasticity effects?

A. The non-price or base (B) delivery forecast does not take into explicit account the impact of electricity price changes on end-use consumption. The price-effect (P) forecast does. PGE expects customers to respond to price changes by making behavioral changes in the short-term, and over time, making changes to the capital stock including purchasing more energy efficient appliances and equipment that would reduce energy consumption.

Q. How do you specifically account for the impact of a price change in the test year forecast?

A. We calculate the implied demand elasticity of the price model by varying price levels, e.g., by 10%. Demand elasticity is the ratio of the percent change in demand, kWh delivery in this case, to the percent change in "real" price. For the test year forecast, we first calculated the kWh demand change based on an assumed price change and the estimated price elasticity, and then adjusted the base forecast by the demand change estimate. This is the same procedure used in previous rate cases.

Q. What price change assumptions did you make to calculate the price effect on demand?

A. In 2013 we assumed a real price change for residential customers of 0.4%, beginning October 1st of 2013, related to the Schedule 102 Regional Power Act Exchange Credit. In 2014 we assumed prices for residential customers to be 9.4% (which also reflects the 0.4% increase from 2013) above November 2012 levels in "real" terms and for commercial customers 3.75% above November 2012 levels in "real" terms. November 2012 was the last historical data point available at the time of the forecast.

Q. What price elasticity does PGE estimate and use in the forecast?

A. We used elasticity estimates of -0.10 for residential demand and -0.03 for nonresidential demand. They were derived from a "price" model that was re-estimated in September 2011 and remain essentially unchanged from previous estimates. A price elasticity of -0.1 means that if electricity prices rose an average of 10%, kWh demand would decline by 1.0%, all else equal. As we pointed out in UE 180, UE 197, and UE 215 these elasticity estimates have remained stable since 2002. Using these estimates of elasticity and the assumed price increases, the price-effect (P) forecast is about 88.7 million kWh or 0.5% lower than the base (B) forecast for 2014.

Q. Did you make any adjustments beyond the impact of electricity price changes to the delivery forecast?

A. Yes. We adjusted the forecast to account for the impact of PGE's incremental EE programs funded through Schedule 109 Incremental Energy Efficiency Funding enabled by SB 838. Energy efficiency trends, including SB 1149 measures are captured implicitly in the forecast model and therefore no explicit adjustment is necessary. The assumed EE program levels incorporate new funding for EE programs beyond prior levels, starting in December 2012.

The Energy Trust of Oregon (ETO) developed the estimates of these "incremental savings" for PGE based on measures achievable at a levelized cost up to 9 cents per kWh for a cost-effectiveness upper limit, or an average levelized cost of 3.6 cents per kWh. We assumed these EE savings to have an effect beginning in December 2012 and continue at a similar pace through 2014.

Q. How significant is the impact of these incremental energy efficiency programs savings on PGE's delivery forecast?

A. We estimate a total of 242.5 million kWh or 1.2% savings from these programs in the 2014 test year based on a gradual ramp-up of programs starting in December 2012 through December 2014. PGE Exhibit 1304 shows the savings from the incremental energy efficiency programs that are included in PGE's delivery forecast.

II. Model Mechanics

Q. Please summarize the process you use to develop the retail energy delivery forecast.

A. The core retail energy delivery (load) model and the forecast process are the same as those we have used in previous rate cases and regulatory filings. The model was estimated using data from an extended historical period through July 2012. Estimation of the model is the process of applying regression techniques to obtain, from the updated or extended historical data, the estimates of the coefficients of the equations that constitute the forecasting model. The most currently available forecasts of the drivers or independent variables to develop our load forecast were then used with the coefficients to develop the retail energy delivery forecast.

Q. Are these models new or different from previous PGE load models?

A. No. The forecast model remains the same as that used in previous filings with the Commission. Past testimony on the PGE load forecast describes in detail the theory and specification of our model, as well as our forecast processes. These were submitted in various regulatory proceedings, most recently in the October filing for the 2013 AUT (Load Forecast Work Papers) and in UE 215 general rate case (PGE Exhibit 1400).

Q. What sources of information do you use to forecast electricity delivery?

A. PGE relies primarily on three sources of economic information to drive our forecast: 1) a national economic forecast, 2) state economic and unemployment forecasts, and 3) a forecast of the California economy. IHS Global Insight provides the US economic forecast. The Oregon Department of Administrative Services, Office of Economic Analysis (OEA) provides the Oregon economic forecast (Oregon Economic and Revenue Forecast) including the state unemployment forecast. The California Employment Development Department

(EDD) provides the forecast of the California economy. We use Global Insight's December 2012 forecast, OEA's December 2012 forecast and the California EDD forecast from May 2012 to develop the kWh delivery forecast for this proceeding. These were all the most current forecast releases available at the time of our delivery forecast. In addition, customers who are large energy users provide us with specific operation information, direct inputs and, if available, forecast of energy use. PGE's Corporate Finance Department also performs credit-risk analysis for these large customers, providing additional credit-risk and financial performance information on our large customers.

Q. Did you make any changes to the model?

A. No, we made no changes to the structure of the model.

Q. What assumption did you make regarding weather variables in the forecast?

A. We used the 15-year average weather observed from 1997 through 2011. Since UE 180, we have been using 15-year moving averages to represent forward looking normal weather conditions.

Q. How current are the data you use to estimate the model?

A. For the estimation of the model used in this proceeding, we used data from 1985 through July 2012 for the residential equations and data from 1990 through July 2012 for the nonresidential equations. A limitation of the NAICS- (North America Industry Classification System) based Oregon employment data dictated the latter choice since this data was not available prior to 1990.

Q. What end-use sectors do you forecast in the model?

A. We forecast demand (kWh delivery) by residential, commercial, manufacturing (industrial) customers and energy served under miscellaneous rate schedules. Residential customers are mostly households, but also include dwellings that PGE has connected for electrical service that are not yet occupied. Commercial customers typically are businesses providing services, such as retail and wholesale establishments, schools, hospitals, government and financial institutions as well as data centers. Manufacturing customers include producers of paper, lumber, steel, machinery, micro-processors, computers, truck and aircraft parts, and shipyards, among others, that serve national and global markets.

In our model, we group commercial and manufacturing customers according to the NAICS definition of business segments. We develop the kWh projections for the three end-use sectors separately and then sum them together with the forecast of existing miscellaneous schedules (streetlight, irrigation, etc.) to obtain total end-use energy.

Finally, we allocate these NAICS-segment delivery forecasts into voltage-level (rate schedule) kWh deliveries using their respective preceding-year ratios. We described in detail these sectors' model specifications and forecast processes in UE 197 and UE 180 testimonies. The model specifications and forecast processes remain the same as those used in UE 215.

Q. Do you make any changes or adjustments to the forecast?

A. We adjust the base (B) delivery forecast results to account for impacts on delivery from any electricity price changes and incremental EE programs.

Q. How do you forecast the ultimate loads delivered to the PGE distribution system?

A. This process involves three steps: 1) aggregate cycle-based sector kWh deliveries are converted into various voltage service levels; 2) cycle-based energy deliveries are converted to calendar-based deliveries using cycle-to-calendar ratios; and 3) add transmission and distribution (line) losses to the kWh deliveries at the meter to obtain the gross (or bus bar) average MW and MW demand (peak) required to meet the end users' demand. For test year 2014, we apply line loss factors based on those used in UE 215. We use monthly and annual voltage-level load factors to calculate the monthly peak MW and annual peak MW based on the projected average MW. PGE Exhibit 1310 displays the forecast of total distribution loads in annual average MW and MW peak demand.

III. Forecast Results

Q. What are the key results of PGE's residential sector forecast?

A. We project 2013 deliveries of 7,611 million kWh using the base model (B) and a lower forecast of 7,588 million kWh to 728,459 residential customers after accounting for the effects of a price change and incremental energy efficiency programs (E). For the test year 2014, we forecast deliveries of 7,685 million kWh (B) and 7,549 million kWh (E), respectively, to 734,050 residential customers. The assumed price increase and the incremental energy efficiency programs combine to reduce deliveries in 2014. These delivery levels reflect a 1.0% (B) and -0.5% (E) change from 2013 to 2014, compared to an actual 0.4% growth in kWh delivery, adjusted for weather, in 2012. Both forecasts include outdoor area lighting energy.

The forecasts include projections of 6,749 new residential connects in 2013 and 7,119 in 2014. The 2014 levels are above the total new residential connects of 5,723 in 2012 that includes actuals through November plus December forecast and 3,413 in 2011, the trough of the current housing market cycle. We forecast 0.7% growth in the number of residential customers in 2013 and 0.8% in 2014, compared to a 0.5% increase in 2012. PGE Exhibit 1305 shows the forecast of building permits, new connects, and occupied accounts. PGE Exhibit 1306 displays the forecast of kWh use per occupied account and deliveries to residential customers in detail.

Q. What are the key results of PGE's commercial sector forecast?

A. We project deliveries to NAICS-based commercial customers of 7,105 million kWh using the base (B) model and 7,048 million kWh after accounting for the effect of incremental energy efficiency programs for 2013 (E). For test year 2014, we forecast deliveries of

7,234 million kWh in the base (B) forecast and 7,076 million kWh in the (E) forecast. As with residential customers, we expect rising electricity prices to have an impact on kWh delivery to commercial customers, albeit to a lesser degree due to this sector's inelastic demand response (i.e., relatively small nonresidential price elasticity). On the other hand, the savings from incremental energy efficiency programs in the commercial sector are larger than those in the residential sector. We forecast energy delivery to this market segment - after accounting for price impacts, EE program savings - to increase 1.4% in 2013 as slow economic growth continues, and to increase 0.4% in 2014 as cumulative savings from incremental EE programs accelerate. Delivery to this market segment, adjusted for weather, declined 0.4% in 2011 and increased 0.2% in 2012. PGE Exhibit 1307 contains the detailed forecast of deliveries to commercial consumers.

Q. What are the key results of PGE's manufacturing sector forecast?

A. We project total deliveries to NAICS-based manufacturing (industrial) customers of 4,068 million kWh using the base model (B) and 4,056 million kWh accounting for price and energy efficiency savings (E) for 2013. For the test year 2014, we forecast deliveries of 4,432 million kWh (B) and 4,395 million kWh accounting for the price adjustment and energy efficiency savings (E). We expect only minimal response to electricity price changes due to the industrial sector's inelastic response and a slightly larger impact from incremental energy efficiency programs. Test year deliveries (E) to industrial customers are projected to be 8.3% higher than the 2013 deliveries albeit 3.0% lower than 2012 weather-adjusted deliveries. Our forecast includes the expansion related to high-tech industry in our service territory. Deliveries to this market segment can show large swings from year to year due to specific individual company operations or industry conditions. PGE Exhibit 1308 contains the detailed delivery forecast of the manufacturing sector.

PGE's manufacturing sector is concentrated in a few energy-intensive industries and large customers. In 2012, high tech industry accounted for over 43% of all industrial energy delivery, the paper industry at roughly 21% and metals at 11%. As a result, when one or several of these large manufacturing customers decide to add capacity or to shut down operations in response to economic conditions, they have a significant impact on our energy delivery forecast.

Q. What are the key results of PGE's miscellaneous rate schedules forecast?

A. Deliveries under miscellaneous schedules accounted for about one percent of total delivery to all retail customers in 2012. PGE Exhibit 1309 sows the forecast of deliveries under these miscellaneous schedules.

IV. Direct Access Forecast

Q. Did you make a separate forecast of delivery to Schedule 485/489 customers?

A. Yes. PGE separates the delivery of energy to customers served under PGE cost-of-service (COS) rates, including variable-price (market power) purchases for customers who choose this option, and delivery of energy to those customers who chose service under Schedule 485/489 (direct access) by 2012 year-end. Schedule 485/489 is the only service under which we forecast customers to receive direct access service in 2014. We pro-rated COS and Schedule 485/489 deliveries by applying the forecasted kWh shares of these customers to their respective historical service level or revenue class. PGE Exhibit 1311 shows the forecast of deliveries in the test year 2014 to PGE COS customers and direct access (Schedule 485/489) customers.

Q. Do you recommend a specific forecast or forecasts of test year 2014 kWh delivery to end-use customers for ratemaking purposes?

A. Yes. We recommend the adoption of the E (post price and energy efficiency) forecast of 19,233 million kWh delivery to all customers.

V. Forecast Uncertainty

Q. How do you address kWh delivery forecast uncertainty?

A. We seek to reduce uncertainty by using current information, data and forecast drivers because conditions could and will likely change between the time PGE develops this forecast and the start of the test year.

Q. Does PGE intend to update its 2014 forecast during this case?

A. Yes, we intend to update the test year delivery forecast as we have in prior cases with the most current input assumptions and, if necessary, re-estimate the model. This would include additional actual load data, more current economic data and forecasts for the US and Oregon and large customers' usage forecasts and other components such as demand elasticity and price changes. Our forecast updates typically occur each quarter, following the release of the Oregon Office of Economic Analysis quarterly forecast.

Q. Is there risk associated with this forecast?

A. Yes. The kWh delivery forecast we submit in this filing is our "expected" or mid-point estimate. As such, it is a 50/50 "point" forecast, 50 percent chance that the actual outcome falls short or exceeds the forecast, typical for "baseline" projections. As with any estimate, actual conditions may differ from what we assumed or anticipated in the forecast, rendering a different outcome.

Q. What are the drivers of uncertainty in PGE's forecast?

A. The accuracy of a forecast depends not only on the performance of the model specification but also on the performance of the independent variables driving the forecast. In our model, the independent variables include temperature, other weather variables that affect energy use and the economic forecast drivers. Our forecast depends on the stability of our model and the accuracy of input assumptions. Our model typically performs well over the sample period, the span over which we estimate the model, as it captures most, if not all, behaviors and relationships such as economic activities or customer response to price changes on energy use. We expect our model to perform equally well over the forecast period if these relationships remain unchanged or stable. If such relationships change in the test year period in response to significant events that were not anticipated or have never occurred over the historical period, our model will become outdated, or in statistical language mis-specified, leading to inaccurate forecasts.

The other major areas of uncertainty involve inputs and assumptions such as the economy, retail electricity prices, key customers' operation decisions, new customers' entry or existing customers' exit and the absence of unforeseen natural disasters, wars or geopolitical turmoil. These variables' future outcomes could turn out differently than anticipated, resulting in a significant variance from the forecast.

Q. Are the input assumptions PGE uses to drive its forecast deterministic or subject to uncertainty?

A. All input assumptions are subject to uncertainty. PGE used as key drivers the December 2012 Global Insight and December 2012 Oregon OEA baseline economic forecasts, which could change going forward as these organizations develop newer forecasts. These economic forecasts have their own issues of uncertainty. Global Insight maintains a fairly symmetrical risk distribution, assigning 60% probability of occurrence to its December 2012 baseline U.S. economic forecast, 20% probability to its Low Scenario (Fiscal Cliff Deadlock Derails the Recovery) and 20% probability to its High Scenario (Recovery Reignites). As economic realities unfold, Global Insight will likely adjust their baseline forecast as well as their uncertainty distribution as they have in the past. For 2014, OEA (December 2012) forecasts total Oregon employment to grow 2.5% from 2013 in its baseline case, bounded by 0.9% growth in the low case and 3.9% growth in the high case. Finally, PGE's key customers could operate differently than planned. They could shut down plants, curtail operations, or add new capacity that we did not anticipate or include in the forecast because of their own economic or unique circumstances. In fact, since the onset of the Great Recession a number of large customers filed for bankruptcy, liquidated business, changed ownership or permanently shut down operations, which has substantially affected PGE actual and anticipated kWh delivery. With respect to announced new development, we specifically included in this forecast expansion by high-tech customers and a growing load related to data centers. If any of these assumptions fails to materialize, significant deviations from the test year forecast would result. The forecast was developed to account for both upside potential (expansion) as well as downside risk, so as not to be too heavily skewed in either direction.

Q. Is weather also an area of uncertainty?

A. Yes. In UE 180, PGE discussed extensively the uncertainty of the delivery forecast with regard to weather in terms of the average or the mean condition and the variance or departure from the average condition in the forecast year. The impact of this uncertainty, expressed as deviation from the mean, is significant because of the large impact of temperature on kWh usage. PGE estimates that one degree variation in temperature could affect (total retail) kWh usage by as much as 1.3% in peak months and as much as 0.6% on an annual basis.

Q. Do changing economic conditions have an effect on PGE's forecast?

A. Yes, very much so. Changing economic conditions could result in activities or outcomes that differ from the economic forecast used to drive PGE's delivery forecast. All else equals, different economic outcomes result in delivery outcomes that differ from the initial forecast. The December 2012 Global Insight US forecast, in its baseline case, envisions the GDP to grow 1.9% in 2013 and 2.7% in 2014 and payroll employment to grow at 1.6% in 2013 and at 1.8% in 2014. This forecast was developed in November and published in early December of 2012.

Similarly, the OEA baseline forecast used in the development of our load forecast was developed in November of 2012. The OEA forecast anticipates Oregon payroll employment to continue growing at a relatively modest pace of 1.6% in 2013 and 2.5% in 2014. Both forecasts were developed based on a number of assumptions including the effectiveness of on-going federal budget, tax policy and debt ceiling negotiations. Numerous risks to the forecasts exist, including the debt-ceiling impasse, federal spending cuts, and global economic recession or another financial crisis. Such an outcome would clearly lead to a significantly lower 2014 test year delivery than we currently forecast.

Q. How important are the assumptions of inputs to PGE's forecast?

A. Assumptions made on the forecast drivers or inputs are extremely important to PGE forecast of kWh delivery, specifically the economic drivers forecasted by Global Insight and the OEA. OEA's forecast of specific industry employment is particularly important as we use them to drive most of the equations in our commercial and industrial sector models. A case in point is what happened in 2009 when the Great Recession hit both the US and Oregon much harder than anticipated in late 2008 by Global Insight and the OEA. Global Insight then forecasted US GDP to grow 1.0% in 2009 and OEA projected Oregon nonfarm employment to gain 0.3% in 2009. In fact, US GDP declined 3.1% in 2009 and Oregon payrolls dropped 6.2% in 2009, indicating that Global Insight over-forecasted the GDP by 4.1% and the OEA over-forecasted Oregon nonfarm employment by 6.5%. Actual energy delivery by PGE, adjusted for weather, was 4.8% below our forecast for 2009 that was based on the August 2008 Global Insight and September 2008 OEA economic forecasts.

Q. Did PGE consider any other economic forecasts for Oregon?

A. Yes. PGE asked Professor Tim Duy, Director of Oregon Economic Forum and developer of the University of Oregon (UO) Index of (Oregon) Economic of Indicators to assess OEA's economic forecast that PGE used to drive our forecast model and to develop either adjustments to the OEA economic forecast or an alternative employment forecast.

Q. Did professor Duy provide PGE with an opinion or forecast?

A. Professor Tim Duy reviewed OEA forecasts and concluded that OEA forecasts from 2009 to 2011 tended to overestimate job growth in Oregon and suggested caution in using the OEA forecast of employment without adjustment for forecast errors. Professor Duy independently forecasts Oregon total nonfarm employment to grow 1.4% in 2013 and 2.1% in 2014 compared to OEA's December 2012 forecast of 1.6% and 2.5% for 2013 and 2014.

Q. Did PGE use Professor Duy's Oregon employment forecast for the 2014 energy delivery forecast?

A. No. However, we remain concerned about the potential for the OEA forecast to overestimate job growth. We are continuing to evaluate alternatives, including the use of Professor Duy's forecast to correct for potential OEA bias.

VI. Qualifications

Q. Mr. Nguyen, please describe your qualifications.

A. I received all my undergraduate and graduate education from the University of Oregon. I received my Bachelor of Arts in 1967 and Master of Science in 1972, both in Economics. I also completed all the course work and examinations for a doctoral degree in Economics, except for the dissertation.

I joined Portland General Electric Company in 1979. Prior to joining PGE, I worked as an independent consultant and later with Northwest Natural Gas Company as an economist. I oversee the development of PGE's economic and energy forecasting models and have the overall responsibility for the development of PGE's economic and energy forecasts. I am currently a member of the Governor's Council of Economic Advisors, State of Oregon, and a panelist of the Western Blue Chip Economic Forecast, Economic Outlook Center, Arizona State University. On various occasions I have served as a member of the Regional Forecast Panel, the Pacific Northwest Executive at the University of Washington; a member of the Northwest Power Planning Council's Economic and Demand Forecasting Advisory Committees.

Q. Ms. Dammen, please describe your qualifications.

A. I received my undergraduate and graduate education from Oregon State University. I received my Bachelor of Arts in 2001 and Master of Science in 2003, both in Economics. I have been a practicing Economist for the past 10 years. Prior to joining PGE I worked at NW Natural, performing load forecasting and developing the IRP; I was an economic consultant at ECO Northwest, specializing in quantitative economics and transportation economics; and was a transportation economist for the U.S. Department of Transportation at the Volpe Transportation Systems Center in Cambridge, MA.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
1301	(Non-Price) Delivery Forecast by market Segment and Service Level
1302	(Price Effect) Delivery Forecast by market Segment and Service Level
1303	(Post Price & EE) Delivery Forecast by Market Segment and Service Level
1304	Forecast of Incremental Energy Efficiency Program Savings
1305	Residential Building Permits, New Connects, Vacancy Rates and Occupied Accounts
1306	Forecast of Residential Use per Occupied Account and Ultimate Deliveries
1307	Commercial Deliveries Forecast by NAICS Cluster
1308	Manufacturing Deliveries Forecast by NAICS Cluster
1309	Forecast of Deliveries under Miscellaneous Secondary Rate Schedules
1310	Total Deliveries and Demand Forecast
1311	Forecast of 2014 Deliveries to Cost-of Service and Direct Access Customers

Delivery Forecast (Base) by Market Segment and Service Level

(at average weather)

Base (not adjusted) Forecast (1)

	(in million kWh)				% Change (2)			
	2011	**2012 (3)**	**2013**	**2014**	**2011**	**2012**	**2013**	**2014**
Schedule 7	7,565	7,594	7,604	7,678	0.2%	0.4%	0.1%	1.0%
Residential Lighting	7	7	7	7	0.0%	0.0%	0.0%	0.0%
Total Residential	7,572	7,600	7,611	7,685	0.2%	0.4%	0.1%	1.0%
Commercial	6,939	6,951	7,105	7,234	-0.4%	0.2%	2.2%	1.8%
Manufacturing	4,469	4,533	4,068	4,432	6.4%	1.4%	-10.3%	8.9%
Miscellaneous Customers	198	205	217	213	1.0%	3.5%	5.9%	-1.8%
Secondary Voltage	7,203	7,209	7,363	7,518	0.3%	0.1%	2.1%	2.1%
Total General Service	7,401	7,414	7,580	7,730	0.4%	0.2%	2.2%	2.0%
Primary Voltage Service	3,078	3,172	3,278	3,615	0.8%	3.1%	3.3%	10.3%
Transmission Voltage Service	1,126	1,102	532	534	20.0%	-2.1%	-51.7%	0.4%
Total Retail	19,177	19,289	19,000	19,564	1.4%	0.6%	-1.5%	3.0%

1/ SDEC12B

2/ calculated from rounded numbers

3/ includes actual weather-adjusted values through December 2012

4/ by NAICS grouping

5/ Total Retail equals Total Residential + Commercial + Industrial + Manufacturing + Miscellaneous. Also equals Total Residential + Total General + Primary Voltage Service + Transmission Service, total may not match due to rounding.

Delivery Forecast (Price) by Market Segment and Service Level

(at average weather)

Net of Price Elasticity (1)

	(in million kWh)				% Change (2)			
	2011	**2012 (3)**	**2013**	**2014**	**2011**	**2012**	**2013**	**2014**
Schedule 7	7,565	7,594	7,603	7,600	0.2%	0.4%	0.1%	0.0%
Residential Lighting	7	7	7	7	0.0%	0.0%	0.0%	0.0%
Total Residential	7,572	7,600	7,610	7,607	0.2%	0.4%	0.1%	0.0%
Commercial	6,939	6,951	7,105	7,229	-0.4%	0.2%	2.2%	1.7%
Manufacturing	4,469	4,533	4,068	4,427	6.4%	1.4%	-10.3%	8.8%
Miscellaneous Customers	198	205	217	213	1.0%	3.5%	5.9%	-1.8%
Secondary Voltage	7,203	7,209	7,363	7,509	0.3%	0.1%	2.1%	2.0%
Total General Service	7,401	7,414	7,580	7,721	0.4%	0.2%	2.2%	1.9%
Primary Voltage Service	3,078	3,172	3,278	3,613	0.8%	3.1%	3.3%	10.2%
Transmission Voltage Service	1,126	1,102	532	534	20.0%	-2.1%	-51.7%	0.4%
Total Retail	19,177	19,289	19,000	19,475	1.4%	0.6%	-1.5%	2.5%

1/ SDEC12P

2/ calculated from rounded numbers

3/ includes actual weather-adjusted values through December 2012

4/ by NAICS grouping

5/ Total Retail equals Total Residential + Commercial + Industrial + Manufacturing + Miscellaneous. Also equals Total Residential + Total General + Primary Voltage Service + Transmission Service, total may not match due to rounding.

Delivery Forecast (Price & Incremental EE) by Market Segment and Service Level

(at average weather)

Net of Price Elasticity and Incremental Energy Efficiency (1)

	(in million kWh)				% Change (2)			
	2011	**2012 (3)**	**2013**	**2014**	**2011**	**2012**	**2013**	**2014**
Schedule 7	7,565	7,594	7,581	7,542	0.2%	0.4%	-0.2%	-0.5%
Residential Lighting	7	7	7	7	0.0%	0.0%	0.0%	0.0%
Total Residential	7,572	7,600	7,588	7,549	0.2%	0.4%	-0.2%	-0.5%
Commercial	6,939	6,951	7,048	7,076	-0.4%	0.2%	1.4%	0.4%
Manufacturing	4,469	4,533	4,056	4,395	6.4%	1.4%	-10.5%	8.4%
Miscellaneous Customers	198	205	217	213	1.0%	3.5%	5.9%	-1.8%
Secondary Voltage	7,203	7,209	7,300	7,340	0.3%	0.1%	1.3%	0.5%
Total General Service	7,401	7,414	7,517	7,552	0.4%	0.2%	1.4%	0.5%
Primary Voltage Service	3,078	3,172	3,272	3,597	0.8%	3.1%	3.2%	9.9%
Transmission Voltage Service	1,126	1,102	532	534	20.0%	-2.1%	-51.7%	0.4%
Total Retail	19,177	19,289	18,909	19,233	1.4%	0.6%	-2.0%	1.7%

1/ SDEC12E

2/ calculated from rounded numbers

3/ includes actual weather-adjusted values through December 2012

4/ by NAICS grouping

5/ Total Retail equals Total Residential + Commercial + Industrial + Manufacturing + Miscellaneous. Also equals Total Residential + Total General + Primary Voltage Service + Transmission Service, total may not match due to rounding.

Forecast of Incremental Energy Efficiency (EE) Savings

(in million kWh)

	2012 (1)	2013	2014
Base (B) Forecast	19,274	19,000	19,564
Price (P) Forecast	19,274	19,000	19,475
Incremental EE Savings (2)	(1)	(91)	(243)
Post-EE Forecast (E)	19,273	18,909	19,233

1/ 2012 kWh are actual weather-adjusted through November 2012, EE savings start in December of 2012.

2/ Energy Trust of Oregon (ETO) annual savings

Residential Building Permits, New Connects, Vacancy Rates and Occupied Accounts History and Forecast

	2010	2011	2012 (1)	2013 (2)	2014
Building Permits (3)					
Single-Family	5,816	5,241	6,527	7,164	7,293
Multi-Family	1,777	2,793	4,214	3,874	4,148
New Connects					
Single-Family	2,292	2,242	2,699	4,187	4,722
Multi-Family	1,093	1,112	2,484	2,502	2,313
Mobile Home	69	38	22	36	60
Other	14	21	16	24	24
Total Connects	3,468	3,413	5,723	6,749	7,119
Vacancy Rates (%)					
Single-Family	3.9%	3.8%	3.9%	4.3%	4.4%
Multi-Family	7.9%	6.9%	6.9%	8.3%	8.5%
Mobile Home	8.1%	8.1%	8.0%	8.0%	8.0%
Number of Occupied Accounts					
Single-Family Heat	105,018	105,033	104,839	104,436	104,507
Single-Family Non-Heat	328,887	330,440	332,056	332,996	335,886
Multiple-Family Heat	158,624	160,948	161,667	160,759	161,192
Multiple-Family Non-Heat	50,007	51,191	51,910	52,108	53,117
Mobile Home Heat	28,283	28,159	28,076	27,899	27,712
Mobile Home Non-Heat	3,566	3,554	3,573	3,556	3,536
Other	5,165	5,105	5,029	4,995	4,967
	-	-	-		
Total Occupied Accounts	679,550	684,431	687,150	686,750	690,918
Total Number of Accounts (4)	717,719	720,056	723,440	728,459	734,050

1/ includes actuals through December 2012, except for building permits and connects which include actuals through November 2012.

2/ forecasted values are identical for base, price-effect and energy efficiency forecast

3/ Oregon building permits

4/ includes vacant accounts

Forecast of Residential Use per Occupied Account and Ultimate Deliveries

(at average weather)

Net of Price Elasticity and Incremental Energy Efficiency (1)

Use per Occupied Account (kWh)	2010 (2)	2011	2012 (3)	2013	2014
Single-Family Heat	15,900	15,878	15,935	16,037	15,871
Single-Family Non-Heat	10,918	10,845	10,803	10,767	10,648
Multiple-Family Heat	9,053	9,023	9,099	9,075	8,970
Multiple-Family Non-Heat	6,545	6,566	6,533	6,510	6,482
Mobile Home Heat	15,174	15,290	15,372	15,377	15,317
Mobile Home Non-Heat	11,418	11,488	11,495	11,431	11,384
Other	10,528	10,605	10,516	10,549	10,540
Average Use per Occupied Account	11,108	11,054	11,051	11,039	10,917
Ultimate Deliveries (million of kWh)					
Single-Family Heat	1,670	1,668	1,671	1,675	1,659
Single-Family Non-Heat	3,591	3,584	3,587	3,586	3,577
Multiple-Family Heat	1,436	1,452	1,471	1,459	1,446
Multiple-Family Non-Heat	327	336	339	339	344
Mobile Home Heat	429	431	432	429	424
Mobile Home Non-Heat	41	41	41	41	40
Other	54	54	53	53	52
Schedule 7 Deliveries	7,548	7,565	7,594	7,581	7,542
Residential Lighting	7	7	7	7	7
Total Residential Deliveries	7,555	7,572	7,600	7,588	7,549

1/ SDEC12E

2/ weather-adjusted

3/ includes actual weather-adjusted values through December 2012

Commercial Deliveries Forecast by NAICS Cluster

(at average weather)

Net of Price Elasticity and Incremental Energy Efficiency

	(in million kWh)				% Change (1)			
	2011	2012 (2)	2013 (3)	2014	2011	2012	2013	2014
Food Stores	460	457	472	476	-2.7%	-0.7%	3.3%	0.8%
Govt. & Education	999	988	997	1,006	0.9%	-1.1%	0.9%	0.9%
Health Services	708	716	720	724	0.3%	1.1%	0.6%	0.6%
Lodging	106	107	109	110	0.0%	0.9%	1.9%	0.9%
Misc. Commercial	662	658	665	662	-0.3%	-0.6%	1.1%	-0.5%
Department Stores/Malls	340	346	346	344	-0.3%	1.8%	0.0%	-0.6%
Office & F.I.R.E. (4)	1,014	1,022	1,020	1,020	1.2%	0.8%	-0.2%	0.0%
Other Services	816	823	832	835	-0.9%	0.9%	1.1%	0.4%
Other Trade	734	723	743	745	-2.5%	-1.5%	2.8%	0.3%
Restaurants	458	465	466	465	0.4%	1.5%	0.2%	-0.2%
Trans., Comm. & Utility	642	646	678	689	-1.8%	0.6%	5.0%	1.6%
Total Commercial	6,939	6,951	7,048	7,076	-0.4%	0.2%	1.4%	0.4%

1/ calculated using rounded-numbers

2/ includes actual weather-adjusted deliveries through December 2012

3/ forecasted values are price elasticity and incremental EE adjusted Forecast

4/ Finance, Insurance, and Real Estate

Manufacturing Deliveries Forecast by NAICS Cluster

(at average weather)

Net of Price Elasticity and Incremental Energy Efficiency

	(in million kWh)				% Change (1)			
	2011	2012 (2)	2013 (3)	2014	2011	2012	2013	2014
Food & Kindred Products	211	220	215	213	0.5%	4.3%	-2.3%	-0.9%
High Tech	1,899	1,954	2,001	2,255	0.4%	2.9%	2.4%	12.7%
Lumber & Wood	97	98	97	99	-4.9%	1.0%	-1.0%	2.1%
Primary & Fab. Metals	520	512	524	530	7.0%	-1.5%	2.3%	1.1%
Other Manufacturing	624	652	695	772	7.8%	4.5%	6.6%	11.1%
Paper & Allied Products	938	916	326	324	24.2%	-2.3%	-64.4%	-0.6%
Transportation Equipment	180	181	199	203	0.0%	0.6%	9.9%	2.0%
Total Manufacturing	4,469	4,533	4,056	4,395	6.4%	1.4%	-10.5%	8.4%

1/ calculated using rounded-numbers

2/ includes actual weather-adjusted deliveries through November of 2012

3/ price elasticity and incremental EE adjusted Forecast

Forecast of Deliveries under Miscellaneous Secondary Rate Schedules

Net of Price Elasticity and Incremental Energy Efficiency

	(in million kWh)				% Change (1)			
	2011	2012 (2)	2013	2014	2011	2012	2013	2014
Secondary (Residential)								
Outdoor Area Lighting (15R) (4)	6.9	6.8	6.9	6.9	0.0%	-1.4%	1.5%	0.0%
Secondary (Commercial)								
Outdoor Area Lighting (15C) (5)	16.3	16	16.2	16.2	0.0%	-1.8%	1.3%	0.0%
Farm Irrigation et al. (6)	71	78.3	88.6	89.7	1.6%	10.3%	13.2%	1.2%
Street and Other Lighting (7)	110.5	110.7	111.8	106.7	0.2%	0.2%	1.0%	-4.6%
Total Miscellaneous Commercial	197.8	204.9	216.7	212.6	0.7%	3.6%	5.8%	-1.9%
All Miscellaneous Schedules (8)	204.7	211.8	223.5	219.5	0.7%	3.5%	5.5%	-1.8%

1/ calculated from rounded numbers

2/ includes actual deliveries through December 2012.

3/ identical for non-price, price-effect and post-EE forecasts

4/ existing Schedule 15R

5/ existing Schedule 15C

6/ existing Schedules 47 & 49

7/ existing Schedules 91, 92 & 93, and new Schedule 95 beginning in 2013.

8/ equals line 2 + line 7

Total Delivery and Demand Forecast

(at average weather)

Net of Price Elasticity and Incremental Energy Efficiency

	Million kWh	Average MW	Peak MW
2008	19,709	2,395	4031
2009	19,191	2,310	3949
2010	18,920	2,283	3582
2011	19,177	2,317	3555
2012	19,273	2,315	3597
2013	18,909	2,322	3702
2014	19,233	2,360	3742

1/ cycle-month basis, at end-user meters; includes actual deliveries through December 2012.

2/ calendar basis, delivered to PGE's distribution system weather-adjusted actuals through December 2012.

3/ coincidental annual system peak; includes actual through December 2012, not adjusted for weather.

4/ price elasticity and incremental EE adjusted forecast.

5/ price elasticity and incremental EE adjusted forecast.

Forecast of 2014 Deliveries to Cost of Service and Non-Cost-of-Service Customers

Net of Price Elasticity and Incremental Energy Efficiency

(in million kWh)

	Cost of Service	Direct Access (1)	Total Delivery (2)
Residential	7,549	-	7,549
Secondary	7,011	435	7,446
Primary	2,878	719	3,597
Transmission	205	329	534
Lighting	107	-	107
Total Retail (2)	17,749	1,484	19,233

1/ Schedule 485/489 deliveries including contract described in Advice filing 1227, December 21, 2012.
2/ Totals may not add due to rounding.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 262

Marginal Cost of Service

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Bonnie Gariety
Robert Macfarlane
Bruce Werner

February 15, 2013

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I. Introduction and Summary

Q. Please state your names and positions.

A. My name is Bonnie Gariety. I am responsible for the Customer Service Marginal Cost Study, which are in Section IV.

My name is Robert Macfarlane. I am responsible for the Generation Marginal Cost Study in Section II.

My name is Bruce Werner. I am responsible for the Distribution Marginal Cost Study in Section III.

We are Pricing and Tariffs Analysts in the Rates and Regulatory Affairs Department for PGE. Our qualifications are described in Section V.

Q. What is the purpose of your testimony?

A. The following testimony and accompanying exhibit describe our Marginal Cost Studies including: Generation, Distribution, and Customer Service marginal cost estimates. Our testimony is organized in the order listed above, and PGE Exhibit 1401 is a summary of these marginal costs by component. The summary consists of generation energy and capacity costs, and costs by PGE rate schedule for; subtransmission, substation, feeder backbone and tapline, transformers, service laterals, meters and customer service costs.

Q. How are the results of these studies used?

A. Witnesses Cody and Macfarlane (PGE Exhibit 1500) use the results of this study to spread PGE's proposed revenue requirement across the relevant customer classes as described in their testimony.

II. Generation Marginal Cost Study

Q. What methodology do you propose in this docket?

A. We propose a long-run generation methodology that explicitly takes into account the cost of marginal generation capacity and long-run marginal energy costs. This marginal cost methodology is consistent with our most recent Integrated Resource Plan (IRP), which identifies a need for capacity resources for both the winter and summer periods. This methodology is similar to the long-run methodology we used in UE 215.

Q. Please describe the methodology used in UE 215.

A. In UE 215 we defined the long-run marginal generation resource as a combined cycle combustion turbine (CCCT) for baseload purposes. We used the fixed costs of an LMS 100 simple cycle combustion turbine (SCCT) to estimate the portion of CCCT fixed costs to assign to capacity. We estimated marginal energy costs using the weighted values of the energy portion of the CCCT and a wind plant. We based the weightings on the expected energy from each resource as identified in the then draft 2009 IRP.

Q. What changes do you propose to the methodology used in UE 215?

A. We propose to average the real levelized costs from two models. The first model is similar to the one used in UE 215. The difference is that we use the fixed costs of a reciprocating engine capacity resource to estimate the portion of CCCT fixed costs to assign to capacity. This resource cost is the lesser of the two capacity resources presented in the 2011 IRP Update dated November 23, 2011 (2011 IRP Update)[1].

[1] http://www.portlandgeneral.com/our_company/energy_strategy/resource_planning/docs/irp_nov2011.pdf.

The second model defines the long-run marginal generation resource as a CCCT for baseload purposes. We use the fixed costs of an F-frame SCCT to estimate the portion of CCCT fixed costs to assign to capacity. No further adjustment is made.

Q. Please describe the steps you used to develop the long-run generation allocation in the first model.

A. The first model of generation marginal cost analysis involves the following inputs and steps:

1. Determine both a long-run marginal energy cost and a long-run marginal capacity cost by first defining the marginal long-run generation resource as a CCCT used for baseload purposes.
2. From this analysis, separately estimate the capacity and energy components as follows:
   a) Estimate the marginal cost of future capacity as the fixed cost of a reciprocating engine capacity resource.
   b) Use the capacity resource fixed costs, inclusive of fixed gas transportation, as the portion of the CCCT fixed cost that is assigned to capacity with the remaining CCCT fixed costs assigned to energy.
   c) To the reciprocating engine capacity costs add 12% reserve requirements consistent with PGE's 2009 IRP and associated 2011 and 2012 IRP updates.
3. Estimate the fully allocated cost of a generic wind farm as identified in the IRP.
4. Calculate the weighted average real levelized price of the energy portion from step 2 and the entire cost in step 3. The result provides the long-run marginal energy cost in real levelized terms.

5. Finally, express the capacity value from step 2.c. in real levelized terms.

Q. Please describe the steps you used to develop the long-run generation allocation in the second model.

A. The second model of generation marginal cost analysis involves the following inputs and steps:

1. Determine both a long-run marginal energy cost and a long-run marginal capacity cost by first defining the marginal long-run generation resource as a CCCT used for baseload purposes.
2. From this analysis, separately estimate the capacity and energy components as follows:
   a) Estimate the marginal cost of future capacity as the fixed cost of an F-frame SCCT.
   b) Use these SCCT fixed costs as the portion of the CCCT fixed cost that is assigned to capacity with the remaining CCCT fixed costs assigned to energy.
   c) To the SCCT capacity costs add 12% reserve requirements consistent with PGE's 2009 IRP and associated 2011 and 2012 IRP updates.
3. Finally, express the capacity and energy values in real levelized terms.

Q. How do you derive the generation marginal costs from the two models?

A. For energy, we take a simple average of the real levelized energy values from step 4 of the first model and the energy value in step 3 of the second model. For the capacity, we take a simple average of the real levelized capacity values from step 5 of the first model and the capacity value in step 3 of the second model.

Q. What are the sources of the overnight capital costs for the resources used in the two models?

A. For the CCCT, reciprocating engines capacity resource, and the wind resource; we used the values provided on page 33 of the 2011 IRP Update. For the F-frame SCCT we reviewed the IRPs of several other northwest utilities and used a value of $700 per kW (2014$), a rounded value based on the most typical overnight capital cost.

Q. How did you calculate the 2014 test-period marginal capacity costs?

A. We multiplied the real levelized annual capacity cost described above by the projected 2014 cost-of-service (COS) test-period, peak-hour load. This peak-hour load is projected to occur in January.

Q. How did you allocate the marginal capacity costs to each rate schedule?

A. We allocated the total 2014 test period marginal capacity costs described above on the basis of each schedule's relative contribution to the monthly peak hours contained in the months of January, July, August, and December (4-coincident peak, or 4-CP).

Q. Why did you choose these four monthly peaks?

A. We chose these four months because they are the months with the highest peaks consistent with the periods identified as capacity deficient in the 2009 IRP. Additionally, we chose these months because PGE's highest annual peak hour occurred during one of these four months in nine out of the past ten years and the seasonal peak occurred during one of these four months in 19 out of the 20 seasons.

Q. Please describe how you determined the proportion of marginal energy costs attributable to the CCCT and the generic wind farm.

A. We used the proportion of new gas and renewable resources proposed for the year 2020 as identified on page 10 of the 2012 IRP Update dated November 21, 2012 (2012 IRP Update)[2]. This resulted in an attribution of 80% of marginal energy costs to the energy costs of a CCCT as defined above, and 20% to the fully allocated costs of a generic wind farm.

Q. What is the source of your long-term gas price forecast?

A. We used the long-term gas price forecast contained in our 2012 IRP Update dated November 21, 2012 for the Sumas and AECO hubs. We equally weighted the projected burnertip prices from these two hubs.

Q. Did you include the projected costs of carbon dioxide compliance in your analysis?

A. Yes. We include compliance costs consistent with the environmental assumptions in the 2012 IRP Update.

Q. What is the fully allocated cost of a generic wind farm as specified in the IRP?

A. The cost of a fully allocated wind farm exclusive of wheeling is estimated at $64.31/MWh in real levelized 2014 dollars, consistent with the capital costs on page 33 of the 2011 IRP Update.

Q. How did you shape these energy costs into hourly values?

A. We shaped the weighted marginal energy costs described above into hourly intervals based on the energy price shaping used in PGE's production cost model, Monet.

Q. How did you estimate each rate schedule's marginal energy cost?

A. We performed the following steps to calculate the 2014 hourly load profile and marginal energy cost of each rate schedule:

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[2] http://www.portlandgeneral.com/our_company/energy_strategy/resource_planning/docs/irp_nov2012.pdf.

1. For each schedule and each month, calculate a typical weekday, Saturday, and Sunday load shape using 2011 hourly load profiles.
2. Use these day-type hourly profiles and the projected monthly peak hour loads to shape each schedule's monthly test-period load forecast into hourly values.
3. By hour, sum each schedule's loads from 2 above and compare these hourly sums to the hourly system load forecast. Assign hourly differences between the two quantities on the basis of each schedule's monthly standard deviation of hourly shaped loads in 2 above. These standard deviations are differentiated by weekday, Saturday, and Sunday.
4. Multiply each schedule's shaped hourly load forecast by the corresponding hourly long-term energy cost described above.

Q. How does this projection of hourly interval loads compare to the monthly load forecast submitted in this docket?

A. The energy values by schedule match precisely. However, inserting the projected monthly peak hour loads to smoothed hourly loads, the monthly peak load hours and the hourly loads immediately proximate to the peak load hours can sometimes appear to be somewhat less than smooth. Nevertheless, the hourly interval data yields a more granular basis to allocate the marginal cost of energy relative to simply using monthly energy values and monthly loads.

Q. Does this conclude your description of generation marginal costs?

A. Yes.

III. Distribution Marginal Cost Study

Q. Please summarize how you calculate marginal distribution costs.

A. We separately calculate marginal distribution costs for subtransmission, substations, distribution feeders (backbone facilities and local facilities), line transformers, service laterals, and meters.

Q. How do you calculate the marginal unit costs of subtransmission and substations?

A. We calculate subtransmission and substation marginal unit costs by first summing growth-related capital expenditures over the five-year period 2013-2017. We then annualize these capital expenditures and divide by the growth in system non-coincident peak (NCP). Customers served at subtransmission voltage supply their own substation and are excluded from this calculation.

Q. How do you calculate the marginal unit distribution feeder costs?

A. We estimate distribution feeder unit costs in the following manner:

1. Perform an analysis that places customers on the distribution feeder from which they are currently served.
2. Eliminate any distribution feeders from which we cannot obtain customer information, and which do not conform to "typical" standards. Examples of these "non-typical" feeders are feeders serving customers at 4 kV, or feeders that serve downtown core areas.
3. Perform an inventory of the wire types and sizes for each feeder. Standardize these wire types and sizes to current specifications and then calculate the cost of rebuilding these feeders in today's dollars.

4. Segregate the wire types and sizes into mainline feeders and taplines. Mainline feeders are typically capable of carrying larger loads and are generally closer to the substations from which they originate. Taplines are typically capable of carrying smaller loads and can be remote from substations.
5. For each feeder, allocate the mainline cost responsibility of each rate schedule based on the rate schedule's proportionate contribution to NCP. Calculate a unit cost per kW by totaling the feeder cost responsibilities and dividing by the sum of each schedule's NCP.
6. For each feeder, allocate the tapline cost responsibility of each rate schedule based on the rate schedule's proportionate design demand (estimated peak at the line transformer). Calculate a unit cost per kW for both poly- and single-phase customers by totaling the feeder cost responsibilities and dividing by the sum of each schedule's design demand.
7. Annualize the mainline and tapline unit costs by applying an economic carrying charge.
8. Separately estimate the unit costs of customers greater than 4 MW who are typically on dedicated distribution feeders. Calculate these marginal unit costs (per customer) as the average distance between the substation and the customer-owned facilities. Because new customers on dedicated circuits typically have a redundant feeder, multiply this average distance by two, resulting in a per-customer average of 8,200 feet of dedicated feeders. Finally, apply the annual carrying charge to annualize the cost per customer.

9. Separately estimate the per customer costs of customers served at subtransmission voltage. This is done by first calculating the average distance from the point at which subtransmission voltage customers connect into the subtransmission system from their substation. Then multiply this average distance by the current cost per wire mile and annualize these costs.

Q. Please describe any other considerations in calculating unit feeder costs.

A. Currently, many municipalities require undergrounding of taplines within subdivisions and commercial areas. Therefore, we exclusively used the current cost of underground facilities in our marginal feeder tapline cost calculations.

Q. How do you calculate marginal line transformer and service costs?

A. We calculate each schedule's marginal line transformer and service lateral costs by estimating the cost of providing the average customer within a class with a service lateral and a line transformer (secondary delivery voltage only). We also include the service design costs and any wire costs not captured in the feeder portion of the study. For smaller customers, such as those on Schedules 7 and 32, we estimate the average number of customers on a transformer in order to appropriately calculate the per customer share of service and transformer costs.

Q. Please describe how you calculate the marginal costs of meters.

A. We calculate marginal meter costs as the installed cost of a new Advanced Metering Infrastructure (AMI) meter for each customer and then apply an annual carrying charge.

Q. How do you allocate distribution O&M to each distribution category and ultimately to each rate schedule?

A. We allocate test-period distribution O&M by distribution category to the rate schedules in proportion to each schedule's respective usage times its marginal capital cost.

Q. Does this conclude your description of distribution marginal costs?

A. Yes.

IV. Customer Service Marginal Cost Study

Q. What is the purpose of the customer service marginal cost study?

A. PGE uses the study to guide the allocation of the customer service functional revenue requirements in the ratespread process as specified in ORS 757.652. The customer service marginal costs are separately estimated by metering, billing, and other services.

Q. Is there a new Chart of Accounts by FERC account numbers?

A. Yes. In 2011, PGE replaced its financial system and established new PGE accounts, which are FERC based.[3] In previous rate cases costs were allocated by PGE ledger.

Q. What PGE account numbers are included in the customer service cost?

A. PGE accounts 9020001, 9030001, 9050001, 9080001, and 9090001.

Q. Are descriptions and titles provided for each of the account numbers?

A. Yes. Descriptions and titles for the account numbers listed above are shown in Table 1 below. Account numbers 9020001, 9030001 and 9050001 are customer account expenses and account numbers 9080001 and 9090001 are customer service and informational expenses.

Table 1
Customer Accounts Expense

Account	Title	Description
9020001	Meter Reading Expense	Labor and expenses associated with on- and off-cycle customer meter reading.
9030001	Customer Records & Collections	Includes the cost of labor, materials used and expenses incurred in work on customer applications, contracts, orders, credit investigations, billing and accounting, collections and complaints.
9050001	Misc. Customer Account Expense	Labor and expenses associated with answering residential and non-residential general account questions

[3] See page 4 of PGE Exhibit 1000 regarding the financial system replacement project.

Table 1, continued
Customer Service and Informational Expense

Account	Title	Description
9080001	Customer Assistance Expense	Labor and non-labor expenses associated with market research, promoting safe, efficient and economical use of electricity, managing energy efficiency programs and energy service supplier relationships and maintaining and enhancing customer program technology systems.
9090001	Information and Advertising Expense	Labor and non-labor expenses associated with informational and instructional advertising that conveys information to customers to protect health and safety, to encourage environmental protection, to utilize their electric equipment safely and economically, or to conserve electric energy.

Q. Other than the change in PGE's account numbering system, is the methodology of the study the same?

A. Yes. As with the PGE ledgers, we allocated the PGE account categories directly on the basis of cost causation and a few are allocated based on sub-allocation of the other accounts. After the allocations occur, the total allocations are divided by the projected 2014 customer counts by Schedule. The result is the marginal costs for each rate schedule.

Q. Are the customer marginal costs divided into three categories?

A. Yes. There are metering, billing, and other services marginal costs, which is the same approach as in our previous general rate case.

Q. Are the marginal costs for metering, billing and other services provided?

A. Yes. PGE calculates the marginal customer costs by PGE Standard Service Rate Schedule for metering, billing and other expenses. It also provides the total customer expense, which is the total of the metering, billing and other expenses.

Q. Briefly describe how you calculate the marginal cost of metering, billing and other services.

A. We calculate the marginal cost expected to occur in 2014 by dividing the 2014 allocated amounts by projected 2014 customer counts to derive the marginal cost per customer for each rate schedule.

Q. Are marginal costs allocated based primarily on number of customers, number of meter reads, and write-off dollar amounts?

A. Yes. As with billing, we allocate certain support costs based on sub-allocations within the functional category.

Q. How do you calculate the percentage of write-offs by rate schedule?

A. We total the dollar amount of write-offs for the past three years (2009-2011), and then divide the dollar amount per rate schedule by the total write-off amount to arrive at the percent of write-offs by rate schedule. We use an adjusted write-off amount, excluding Schedules 85 and 89. Therefore, the largest portion of write-offs is allocated to residential customers.

Q. How do you calculate the percentage of meter reads by rate schedule?

A. By 2014 some manual meter reads may still occur, but the number of manual reads will be minimal as we have fully transitioned to AMI. The decline in metering expenses in 2014 reflects this transition. To allocate the remaining metering costs, we use the number of manual meter reads from January 2011 through October 2012. The number of manual meter reads on an annual basis is grouped by meter type (kWh, demand, kvar, time of use, and net meters) and by rate schedule. We estimate how many reads are attributed to the rate schedules and then calculate a percentage by rate schedule. Then the percentage of meters reads is weighted with number of customers (less unmetered and signals) to arrive at a weighted percentage.

Q. What is the basis of the weighted customer counts?

A. We applied a weighting methodology for billing and other services. The weights are based on 2011 costs per customer. The 2011 weight is then multiplied by the projected 2014 number of customers, resulting in an adjusted 2014 customer count. Then the adjusted 2014 customer count is divided by the total number of customers to arrive at a percentage. Finally, that percentage is multiplied by the 2014 costs.

A. Metering

Q. Briefly describe how you calculate marginal costs of metering?

A. Metering costs consist of PGE accounts 9020001. We calculate the marginal cost of metering by allocating the cost to the rate schedules based on various cost-causation principles. For example, we allocate the PGE account 9020001 - "field collections" to metering. We use a weighted percentage of customers (less unmetered lighting and signals) and the most recent meter study. The total allocations are divided by customer counts to arrive at the marginal cost by schedule. Because PGE will have completed its network upgrades for AMI, fewer costs are attributed to metering than the previous GRC.

B. Billing

Q. How do you calculate the marginal costs of billing?

A. Billing costs consist of PGE accounts 9030001. We allocate the collection-related cost on the same basis as the uncollectible accounts. We allocate some of the cost directly on the basis of cost-causation and we allocate some of the other accounts on sub-allocations of the other accounts within billing. For example, "retail receivables" and "field collections" are allocated based on percentage of adjusted write offs by rate schedule. "Specialized billing" costs are allocated by the number of customers on direct access. "Business services group" is allocated by customer. "CIS billing" is allocated by the number of customers, except streetlights and signals. After we allocate the various PGE accounts, we divide the total allocations by the projected customer counts by schedule. This result is the billing marginal cost for each rate schedule.

C. Other Services

Q. How do you calculate the marginal costs of other services?

A. Other services costs consist of PGE accounts 9050001 and 9080001. We calculate the marginal cost of other services by allocating the individual cost to the rate schedules based on various cost-causation principles. For example, we allocate "customer contact operations" by the number of customers on rate schedules using up to 200 kW. The "key customer group" (RC 527) is allocated to all schedules except for residential. However, the allocation is based on a weighting between number of customers and usage. The key customer group is PGE account 9030001, but we have placed it in other services, since this department provides customer service and manages relationships with large customers. After we allocate the individual cost to the individual rate schedules we divide the allocations by the test period customer count to obtain a per customer marginal cost.

Q. Does this conclude your description of customer service marginal costs?

A. Yes.

V. Qualifications

Q. Ms. Gariety, please state your educational background and qualifications.

A. I received a Bachelor of Science and a Master of Science degree in Economics from the University of Wyoming. Since joining PGE in 2007, I have worked as an analyst in the Rates and Regulatory Affairs Department. My duties at PGE have focused on power costs, solar, load curtailment, electric vehicle, and various regulatory issues. Previously, I was an analyst with Iowa Utilities Board and the Office of Consumer Advocate under the Iowa Department of Justice. Also, I was an economist for the State of Oregon Employment Department.

Q. Mr. Macfarlane, please state your educational background and qualifications.

A. I received a Bachelor of Arts business degree from Portland State University with a focus in finance. Since joining PGE in 2008, I have worked as an analyst in the Rates and Regulatory Affairs Department. My duties at PGE have focused on pricing and regulatory issues. From 2004 to 2008, I was a consultant with Bates Private Capital in Lake Oswego, OR where I developed, prepared, and reviewed financial analyses used in securities litigation.

Q. Mr. Werner, please state your educational background and qualifications.

A. I received a Bachelor of Arts degree with an emphasis in Fine Arts from Montana State University in 1977. Since joining PGE in 1999 I have worked as an analyst on a variety of pricing issues in the Regulatory Affairs Department. From 1979 to 1999 I worked at PacifiCorp in several different capacities starting in energy efficiency and finishing in regulatory affairs.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
1401	Marginal Cost Study

PORTLAND GENERAL ELECTRIC
MARGINAL ENERGY COSTS

Schedule	Busbar Energy (MWh)	Marginal Energy Cost
Schedule 7	8,162,952	$398,808,672
Schedule 15	25,007	$1,085,126
Schedule 32	1,712,854	$81,886,302
Schedule 38	32,797	$1,610,351
Schedule 47	23,120	$1,126,022
Schedule 49	73,893	$3,543,605
Schedule 83	3,032,861	$145,785,900
Schedule 85	2,391,879	$114,100,025
Schedule 89 1-4 MW	1,010,377	$48,037,390
Schedule 89 GT 4 MW	2,525,314	$117,581,291
Schedule 91	111,372	$4,832,703
Schedule 92	4,803	$222,413
Schedule 93	615	$29,437
Totals	19,107,843	$918,649,238

PORTLAND GENERAL ELECTRIC
MARGINAL CAPACITY COSTS

Model One - SCCT Proxy Capital Cost $/kW (F Frame)

1 SCCT Installed Cost	$/kW	$766
2 Real Carrying Charge		10.04%
3 Annualized SCCT Cost	$/kW-yr	$76.90
4 Fixed O&M	$/kW-yr	$5.29
5 Fixed Gas Transport	$/kW-yr	$0.00
6 Reserve Margin (12%)	$/kW-yr	$9.86
7 Total	$/kW-yr	$92.05

PORTLAND GENERAL ELECTRIC
MARGINAL CAPACITY COSTS

Model Two - Reciprocating Engines Proxy Capital Cost

1	Recip Eng Installed Cost	$/kW	$1,311
2	Real Carrying Charge		10.04%
3	Annualized Recip Eng Cost	$/kW-yr	$131.63
4	Fixed O&M	$/kW-yr	$3.59
5	Fixed Gas Transport	$/kW-yr	$34.17
6	Reserve Margin (12%)	$/kW-yr	$20.33
7	Total	$/kW-yr	$189.73

PORTLAND GENERAL ELECTRIC
SUMMARY OF MARGINAL COST STUDY

SCHEDULE	SUBTRANSMISSION COSTS ($/kW)	SUBSTATION COSTS ($/kW)	FEEDER BACKBONE COSTS ($/kW)	FEEDER TAPLINE COSTS ($/kW)	SERVICE & TRANSFORMER COSTS ($/Customer)	METER COSTS ($/Customer)	CUSTOMER COSTS ($/Customer)
Schedule 7 Residential							
Single-phase	$10.99	$10.12	$24.23	$17.10	$82.61	$20.19	$72.42
Three-phase	$10.99	$10.12	$24.23	$17.10	$147.47	$55.45	$72.42
Schedule 15 Residential	$10.99	$10.12	$25.26	$17.81	$8.66	N/A	$60.40
Schedule 15 Commercial	$10.99	$10.12	$25.26	$17.81	$8.66	N/A	$100.17
Schedule 32 General Service							
Single-phase	$10.99	$10.12	$28.14	$24.77	$123.07	$19.37	$115.53
Three-phase	$10.99	$10.12	$28.14	$9.44	$264.80	$68.38	$115.53
Schedule 38 TOU							
Single-phase	$10.99	$10.12	$33.47	$20.26	$195.06	$57.76	$106.54
Three-phase	$10.99	$10.12	$33.47	$13.09	$527.62	$82.42	$106.54
Schedule 47 Irrigation							
Single-phase	$10.99	$10.12	$70.23	$52.32	$9.70	$53.83	$105.21
Three-phase	$10.99	$10.12	$70.23	$27.08	$25.26	$81.81	$105.21
Schedule 49 Irrigation							
Single-phase	$10.99	$10.12	$71.65	$44.06	$27.36	$57.76	$119.93
Three-phase	$10.99	$10.12	$71.65	$27.46	$132.97	$99.76	$119.93
Schedule 83 Secondary General Service							
Single-phase	$10.99	$10.12	$24.68	$20.63	$426.41	$46.44	$178.23
Three-phase	$10.99	$10.12	$24.68	$9.00	$1,093.60	$108.37	$178.23
Schedule 85 Secondary General Service	$10.99	$10.12	$21.13	$7.00	$1,732.11	$151.34	$878.76
Schedule 85 Primary General Service	$10.99	$10.12	$21.13	$7.00	$727.44	$1,382.27	$878.76
Schedule 89 Secondary 1-4 MW	$10.99	$10.12	$21.14	$4.66	$4,581.85	$164.19	$3,605.21
Schedule 89 Primary 1-4 MW	$10.99	$10.12	$21.14	$4.66	$867.23	$1,382.27	$3,605.21
Schedule 89 Secondary GT 4 MW	$10.99	$10.12	$73,144	N/A	$11,054.47	$164.19	$41,225.61
Schedule 89 Primary GT 4 MW	$10.99	$10.12	$73,144	N/A	$2,548.39	$1,382.27	$41,225.61
Schedule 89 Subtransmission	$10.99	N/A	$83,464	N/A	N/A	$16,556.61	$41,225.61
Schedules 91 & 95 Streetlighting	$10.99	$10.12	$25.26	$17.81	$5.01	N/A	$770.25
Schedules 92 Traffic Signals	$10.99	$10.12	$25.26	$9.09	$12.09	N/A	$624.90
Schedule 93 Field Lighting	$10.99	$10.12	$25.26	$9.09	$72.37	$1,296.40	$175.03

UE 262 / PGE / 1500
Cody - Macfarlane

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 262

Pricing

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Marc Cody
Robert Macfarlane

February 15, 2013

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I. Introduction and Summary

Q. Please state your names and positions.

A. My name is Marc Cody. I am a Senior Analyst in Pricing and Tariffs for PGE. My qualifications are described in Section VII.

My name is Robert Macfarlane. I am also a Senior Analyst in Pricing and Tariffs for PGE. My qualifications are described in PGE Exhibit 1400.

Q. What is the purpose of your testimony?

A. This testimony and accompanying exhibits demonstrate how our proposed E-18 Tariff changes recover Portland General Electric's (PGE) 2014 revenue requirement in a way that achieves fair, just, and reasonable prices for all our customers. In addition to estimating the overall effect on customer bills, this testimony also describes the revenue requirement allocation process (ratespread), and the rate design. The testimony also discusses topics to which PGE and the City of Portland (COP) stipulated to discuss in PGE's last general rate case, UE 215, streetlight rate design, and changes to various supplemental schedules including Schedule 123 Decoupling Adjustment.

Q. Please summarize the projected Cost of Service rate impacts resulting from the proposed allocations.

A. Table 1 below summarizes the base rate impacts of our proposals for the major rate schedules. Also included in Table 1 is the overall percentage impact inclusive of direct access (DA) customers.

Table 1
Estimated Cost of Service Rate Impacts

	Estimated Rate Change (%) (base rates)
Schedule 7 Residential	8.7%
Schedule 32 Small Nonresidential	10.5%
Schedule 83 31-200 kW	6.3%
Schedule 85 201-4,000 kW	2.5%
Schedule 89 Over 4,000 kW	-0.7%
COS & DA Overall	6.2%

II. Ratespread

Q. Please summarize the changes in ratespread, and rate design you have made from UE 215.

A. The key changes we propose are listed below (and explained in our testimony):

- Consolidate Schedule 85, a schedule currently for customers between 201 and 1,000 kW facility capacity with the smaller customers on Schedule 89, specifically those customers less than or equal to 4,000 kW facility capacity. We propose that Schedule 89 be applicable solely to customers over 4,000 kW commencing in 2014.
- Introduce mandatory Time-of-Use (TOU) pricing for Schedule 83.
- Consolidate Schedule 93 Recreational Field Lighting into Schedule 38 Large Nonresidential Time-of-Day Standard Service.
- Allocate the transmission revenue requirement on a coincident peak basis rather than on the basis of generation allocations.
- Price the poles and luminaires for Outdoor Lighting Schedules 15, 91, and 95 at marginal cost rather than embedded cost.

Q. Do you propose changes to existing supplemental schedules?

A. Yes. We propose some language changes to Schedule 123, the Sales Normalization Adjustment, language changes to Schedule 125, the Annual Power Cost Update, and Schedule 126 Annual Power Cost Variance Mechanism. The changes to Schedules 125 and 126 are consistent with the discussion contained in PGE Exhibit 400. In addition we propose language changes to Schedule 145, the Boardman Power Plant Operating Life Adjustment to reflect the intent of the schedule to recover only the revenue requirements associated with decommissioning of the plant by 2020.

Q. What is the basis for the functional allocation of costs to the rate schedules?

A. PGE uses its Marginal Cost of Service Study to guide the allocation of the generation, distribution, and customer service (separately, Metering, Billing, and Other Consumer Service) functional revenue requirements in the rate spread process. The Marginal Cost Study is presented in PGE Exhibit 1400.

Q. What are the respective capacity and energy percentages used in allocating the generation revenue requirements?

A. Capacity comprises approximately 35% of the marginal cost of generation, and energy 65%. The corresponding figures from UE 215 were 31% and 69% respectively.

Q. What other functional revenue requirement categories do you allocate besides those mentioned above?

A. Because the Ancillary Services revenue requirement is split out from generation, we allocate it in the same manner as we do generation. We also allocate the transmission revenue requirement on a 4-Coincident Peak (4-CP) basis, consistent with how generation capacity is treated in the marginal cost study. These two functional categories combined with the five categories above complete the seven functional categories specified in ORS 757.642.

Q. Why do you propose to allocate the transmission revenue requirements on a 4-CP basis?

A. We propose to allocate the transmission revenue requirement on a 4-CP basis (January, July, August, and December) because additions to the current system are primarily driven by the need to meet future peak winter and summer loads. Hence it is appropriate to allocate the existing transmission system on a 4-CP basis.

Q. Do you allocate other cost categories to the individual rate schedules?

A. Yes. We allocate franchise fees to the schedules on the basis of the test period revenue requirement allocations and Trojan decommissioning on a generation revenues basis. We allocate Schedule 129 Long-Term Transition Adjustment to Schedule 85 and 89 customers on an energy basis, and finally, we allocate uncollectible expense based on historical incidence for the years 2009-2011. All allocations are presented in PGE Exhibit 1504.

Q. Describe how you allocate and price the recovery of the franchise fee revenue requirements consistent with OPUC Order 12-500.

A. We interpret OPUC Order 12-500 to specify that franchise fee revenue requirements be unbundled and priced volumetrically such that direct access customers are not attributed cost responsibility for the generation and transmission functional categories. Thus, we allocated the franchise fee revenue requirements by segregating the generation and transmission revenue requirement test-period allocations from the other revenue requirement allocations across the schedules and separately calculating the prices for each category of allocations. Because direct access customers do not pay generation and transmission charges to PGE, we calculate a franchise fee price differential related to these charges and apply this differential to the direct access schedules. This differential is captured in the system usage charges for each direct access schedule. For direct access schedules that do not have a system usage charge, we establish a price differential within the volumetric distribution charges.

Q. Do you propose any form of rate mitigation or other deviation from using marginal cost to spread the revenue requirements?

A. Yes, <u>after</u> spreading the revenue requirements we apply the Customer Impact Offset (CIO) in order to temper the rate impacts to certain schedules. Specifically, we limit the rate increase for Schedules 47 and 49 to 17%, similar to how we treated these schedules in

UE 215. When allocating the CIO we do not propose any surcharges for Schedules 7 and 32 because for these schedules the increases are above the average increase. In addition, because the Schedule 7 and 32 percentage increases are much larger than the overall increase, we propose to partially mitigate these increases. We base this partial mitigation on the Schedule 129 Long-term Transition Adjustments that would have accrued to Schedules 7 and 32 if we had spread the allocation of these transition adjustments to all schedules, rather than to Schedules 85 and 89 and their direct access equivalents as specified in the Special Conditions to Schedule 129. It is appropriate to do this because Schedules 7 and 32 bear a heavy burden of the fixed generation costs that are reallocated during a general rate proceeding.

Q. Why do you propose this specific partial mitigation to Schedules 7 and 32?

A. We propose this specific partial mitigation because the $13.2 million of Schedule 129 Transition Adjustments are spread as credits solely to Schedules 85 and 89 and their direct access equivalents. At the same time, in a general rate proceeding such as this, the fixed generation costs are spread to all customers except those on long-term direct access. Our proposal for Schedules 7 and 32 helps mitigate the current situation where the customers eligible to participate in long-term direct access can escape the responsibility of paying for fixed generation costs, to the detriment of other customers.

III. Rate Schedule Design

Q. Please provide a brief summary of the major Cost of Service Rate Schedules.

A. There are five major Cost of Service (COS) rate schedules:

Schedule 7, Residential Service, currently consists of a monthly Basic Charge, volumetric Transmission and Distribution Charges, and a two-block energy rate.

Schedule 32, Small Nonresidential Standard Service, consists of a monthly Basic Charge, a volumetric Transmission Charge, and a two-block Distribution Charge. The Energy Charge is flat across all energy usage.

Schedule 83, Large Nonresidential Standard Service, is applicable to all secondary voltage Large Nonresidential customers between 31 and 200 kW, except for certain specialty schedules. This schedule contains more complex charges than Schedules 7 and 32. In addition to the basic charges, there is a Transmission Demand Charge based on the highest metered kilowatt (kW) reading for a 30 minute period during the monthly billing cycle. There is also a Distribution Demand Charge based on the same criteria above, and a Distribution Facility Capacity Charge based on the average of the two greatest monthly Demands within a 12-month period (Facility Capacity). We propose that the Energy Charge be mandatory TOU.

Schedule 85, Large Nonresidential Standard Service (201 kW to 4,000 kW), is an existing schedule currently applicable to customers from 201 kW to 1,000 kW. The Schedule 85 Transmission and Distribution Demand Charges as well as the Facility Capacity Charges are based on the same criteria as they are for Schedule 83. We propose that the Energy Charges continue to be on- and off-peak differentiated.

We propose to consolidate this existing schedule with the smaller customers (<= 4,000 kW) that are currently on Schedule 89. We propose this consolidation for the following reasons:

1) The smaller customers on current Schedule 89 have load profiles and distribution costs that are more similar to Schedule 85 customers than to the larger Schedule 89 customers.
2) Combining the smaller customers on current Schedule 89 with the Schedule 85 customers will allow for better cost attribution to the remaining larger Schedule 89 customers. For example, the larger customers within the current Schedule 89 have higher non-coincident peak load factors than the smaller Schedule 89 customers by virtue of their relatively flatter load profile. As mentioned above, the larger customers also have lower unit distribution costs. Therefore it is reasonable to evaluate other cost differences such as generation and customer-related costs for customers above 4,000 kW.

Schedule 89, Large Nonresidential (>4,000 kW) Standard Service, is a schedule currently applicable to customers whose Facility Capacity exceeds 1,000 kW. This schedule contains Transmission and Distribution Demand Charges that are based on the 30-minute periods that occur during on-peak intervals. These on-peak intervals are defined as between 6:00 a.m. and 10:00 p.m., Monday through Saturday. The Schedule 89 Distribution Facility Capacity Charge billing determinant is calculated in the same manner as for Schedules 83 and 85. The Energy Charges will continue to be on- and off-peak differentiated. As mentioned above, we propose to move the smaller customers on this schedule to Schedule 85. Schedule 89 will then be applicable to customers greater than 4,000 kW.

Q. What principles guided you in developing the proposed prices?

A. We were guided by the following Bonbright[1] principles in both the cost allocation and pricing processes. The proposed prices should accomplish the following:

1) Recover the total revenue requirement;
2) Provide revenue stability and predictability to the utility;
3) Provide rate stability and predictability to customers;
4) Reflect the cost of providing service to the customer classes;
5) Be fair to the customer classes;
6) Send appropriate price signals; and
7) Be simple and understandable.

Q. How did PGE develop the prices for each rate schedule?

A. We explain the development of prices for each of the major rate schedules below. PGE Exhibit 1503, Rate Design, provides additional detail regarding how the individual prices for each schedule were designed.

Q. Please list the individual prices for Schedule 7, Residential Service.

A. The prices are summarized below:

Table 2
Schedule 7
Residential Service Proposed Prices

Category	Prices
Basic Charge	$10.00 per customer per month
Transmission & Related Service Charge	2.99 mills per kWh
Distribution Charge	39.62 mills per kWh
Energy Charge First 1,000 kWh	64.34 mills per kWh
Energy Charge Over 1,000 kWh	71.56 mills per kWh

[1] "Principles of Public Utility Rates," by James C. Bonbright, Albert L. Danielsen, and David R. Kamerschen, 2nd Edition, 1988.

Q. Please explain how you developed these prices.

A. Although the Marginal Cost Study results suggest a **Basic Charge** of approximately $21, we propose to increase the single-phase charge by one dollar to $10.00 in order to better match prices to costs. This proposal brings the charge back to the level it was from October 1, 2001, to December 31, 2010. We reduced the Basic Charge in 2011 to $9.00 in order to mitigate the impact on our lower use customers that resulted from changes in blocking of energy charges that were proposed by several parties in that case. We propose to set the three-phase Basic Charge to the same $10.00 amount for administrative simplicity. There are fewer than 100 residential three-phase customers, hence setting the basic charges at the same level may lead to fewer Schedule 7 rate permutations in the future. We develop the **Transmission & Related Service Charge** directly from the allocated transmission and ancillary services revenue requirement.

We calculate the **Distribution Charge** of 39.62 mills per kWh from the allocated distribution costs and from the allocated costs not recovered by the other charges. The Distribution Charge also includes the allocation of franchise fees and Trojan Decommissioning costs.

We maintain the Schedule 7 blocked **Energy Charges** structure of under/over 1,000 kWh with a price differential of 7.22 mills per kWh.

Q. Did you incorporate a projection of the revenue impacts of the voluntary portfolio TOU option in the calculation of the energy price?

A. Yes. We estimate that by continuing to price the voluntary TOU customers in a manner that presumes their load shape is the same as the overall rate schedule, PGE will incur a revenue shortfall of approximately $81,000. We incorporate this impact in to the standard Schedule 7 energy charge.

Q. Please list the individual prices for Schedule 32, Small Nonresidential Service.

A. The prices are summarized below:

Table 3
Schedule 32
Small Nonresidential Service

Category	Price
Basic Charge Single Phase	$14.00 per customer per month
Basic Charge Three Phase	$18.00 per customer per month
Transmission & Related Services Charge	2.48 mills per kWh
Distribution Charge First 5,000 kWh	44.01 mills per kWh
Distribution Charge Over 5,000 kWh	8.33 mills per kWh
Energy Charge	60.24 mills per kWh

Q. Please describe how you developed the Schedule 32 prices.

A. Schedules 32 and 532 apply to Small Nonresidential customers, with Facility Capacity less than 30 kW. Schedule 532 (applicable to Direct Access Service) is actually a subset of Schedule 32 in that it contains some, but not all, of the cost components of Schedule 32. Small Nonresidential customers receive service at secondary voltage, and other than the Basic Charge, all charges are expressed as a volumetric kWh charge. As with Schedule 7, the applicable costs are allocated into the Basic, Transmission, Distribution and Energy Charge categories. To better reflect costs, we increase the Basic Charge for single- and three-phase service to $14.00 and $18.00 per month from their current levels of $12.00 and $16.00 respectively. These basic charges are still considerably below the marginal customer-related costs of approximately $32 and $52. As with Schedule 7, we capture the difference between the allocated costs and the various revenues within the Distribution Charge.

We compute the **Transmission and Related Services Charge** directly from the allocated transmission and ancillary service costs.

We retain the current Schedule 32, **Distribution Charge** blocking, with the initial block including usage up to 5,000 kWh. We set the second block for usage greater than 5,000 kWh on a declining basis to 6 mills per kWh (prior to adding the System Usage Charge) in order to provide a transition to Schedule 83 for customers whose loads have exceeded 30 kW at least twice during the preceding 13 months. We set this tailblock rate at a higher level than in UE 215 consistent with the increased price for the first block. The design provides effective rate migration for customers who migrate from volumetric-based distribution pricing to demand-based distribution pricing (Schedule 32 to 83). Similar to Schedule 7, we include within the Distribution Charge the costs associated with franchise fees and Trojan Decommissioning.

We set the **Energy Charge** on a flat year-round basis that is based on the allocation of generation costs.

Q. Did you incorporate a projection of the revenue impacts of the voluntary portfolio TOU option in the calculation of the energy price?

A. Yes. We estimate that by continuing to price the voluntary TOU customers in a manner that presumes their load shape is the same as the overall rate schedule, PGE will incur a revenue shortfall of approximately $44,000. We incorporate this impact in to the standard Schedule 32 energy charge.

Q. Briefly describe Schedule 532.

A. Schedule 532 sets out the charges associated with PGE's transmission and distribution services. Energy supply and transmission costs are excluded because the customer's Energy Service Supplier (ESS) provides these services.

Schedule 532 includes the same Basic and Distribution Charges as Schedule 32, with one exception, a distribution price reduction associated with franchise fees discussed earlier in testimony. We incorporate a Daily Price Energy Charge into Schedule 32 in order to address the potential cost impact of customers switching from Schedule 532 to Schedule 32 prior to completing at least one year of service on Schedule 532. The daily price tracks the daily market price for power and is based on the secondary voltage Daily Price option in Schedule 83.

Q. Please provide the proposed prices for Schedule 83 and describe the customers to whom these prices apply.

A. Schedule 83 applies to all Nonresidential customers with Facility Capacity loads greater than 30 kW and less than or equal to 200 kW. We use the same approach and cost causation principles as described for Residential and Small Nonresidential service in designing these rates.

The Schedule 83 charges include more detail because Large Nonresidential customers are generally more sophisticated energy users and are more able to react to pricing signals triggered by their peak consumption. Schedule 83 is for secondary delivery voltage only. The proposed prices are below:

Table 4
Schedule 83
General Service 31-200 kW

Category	Monthly Price	
Basic Charge Single Phase	$30.00	per customer per month
Basic Charge Three Phase	$40.00	per customer per month
Trans. & Related Services	$0.88	per kW peak Demand
Distribution Demand Charge	$2.05	per kW peak Demand
Facility Capacity Charge (First 30 kW)	$2.98	per kW Facility Capacity
Facility Capacity Charge (Over 30 kW)	$2.48	per kW Facility Capacity
System Usage Charge	8.49	mills per kWh
COS Energy Charge On-peak	61.78	mills per kWh
COS Energy Charge Off-peak	54.78	mills per kWh

Q. Please describe how you developed the Schedule 83 prices.

A. We propose to increase the Schedule 83 single-phase **Basic Charge** to $30.00 and to increase the three-phase charge to $40.00. This pricing level better reflects cost-causation principles and helps enable a smooth transition for Schedule 32 customers whose demand exceeds 30 kW. Similar to Schedule 32, these basic charges are set considerably below the marginal customer-related costs. The System Usage Charge recovers the remaining customer-related costs as well as any other costs either not fully recovered or more than fully recovered through the appropriate charge.

For Schedules 83, we set the **Transmission & Related Service Charge** to $0.88 per kW consistent with the other secondary voltage customers served on Schedules 85 or 89. We do this to make the pricing more consistent for customers who choose Direct Access Service under Schedules 583, 585 or 589. This charge results in more than a full recovery of Schedule 83 allocated costs, consequently we flow the over-recovery through to the System Usage Charge.

The **Distribution Charges** for Schedule 83 consist of a **Demand Charge** and a **Facility Capacity Charge**. We recover the costs associated with the 13 kV system through the Facility Capacity Charge. We set the Facility Capacity Charge for the first 30 kW at a higher level than the Facility Capacity Charge for over 30 kW to once again provide a smooth transition for Schedule 32 customers who migrate to Schedule 83 because their Demand exceeds 30 kW. This declining block structure also reflects the declining unit cost nature of the distribution system.

We set the **Demand Charge** which recovers substations and 115 kV costs where applicable, at $2.05 per kW by combining the demand-related costs and billing determinants for Schedules 83, 85, and 89 such that these schedules will have the same secondary voltage and primary voltage demand charges. Any over- or under-collections of these demand-related costs are captured through other charges applicable to the specific schedules.

Because several energy options are available to Schedules 83 and 583, we separately state the **System Usage Charge.** This charge recovers franchise fees and Trojan Decommissioning costs, as well as any other costs not fully recovered by the other charges. Again, the System Usage Charge is lower for Schedule 583 than for Schedule 83 because Schedule 583 customers are not charged for generation and transmission by PGE.

We calculate the COS Energy Charges based on the results of the generation allocations. For the reasons we describe later in Section V, we propose implementing TOU energy charges for this schedule. We set on-and off-peak differential at a relatively low 7 mills per kWh in order to allow customers to become accustomed to TOU pricing.

Q. Please describe the Schedule 83 Energy Charge options.

A. Schedule 83 customers may choose to receive energy either from PGE based on PGE's COS energy option or from PGE's market-based energy option. The market-based option available to Schedule 83 is daily pricing based on the prices for the Mid-Columbia hub as reported by the Dow Jones Mid-Columbia Daily On- and Off-Peak Firm Pricing Index (Dow Jones). Customers may also choose to receive service from an ESS.

We propose that customers receiving service from an ESS or from a PGE market option receive the Schedule 128, Short-Term Transition Adjustment. However, we propose to no longer differentiate Schedule 128 into on- and off-peak periods as we currently do for Schedules 585 and 589.

Q. What schedule is applicable to Schedule 83 customers who wish to elect the Direct Access energy option?

A. Customers choosing the Direct Access energy option will take service under the provisions of Schedule 583. Schedule 583 pricing mirrors Schedule 83 except that it contains neither a PGE-supplied energy price, nor a Transmission & Related Services Charge.

Q. Why do you propose to eliminate the current Schedule 128 TOU structure for certain schedules?

A. We propose this because the current structure does not provide meaningful price information. Essentially, the manner in which Schedule 128 is currently calculated yields results that differ little from what would prevail with flat transition adjustments. Indeed, at times the results can be counterintuitive. For example, our current off-peak Schedule 128 Transition Adjustments for Schedule 89 Primary are higher than our current on-peak prices.

Q. Are there other reasons to eliminate the current Schedule 128 TOU structure for certain schedules?

A. Yes. Eliminating the Schedule 128 TOU structure provides consistency with Schedule 129 Long-term Transition Adjustment, and should be more simple to administer.

Q. Do you wish to discuss any other changes you propose to make to Schedule 128?

A. Yes. Because we propose to reduce the Distribution or System Usage Charges for the Schedule 500-related direct access schedules consistent with OPUC Order 12-550, we gross-up the Schedule 128 transition adjustments for the franchise fee revenue requirement percentage rate of approximately 2.50%. PGE will pay franchise fees to the municipalities based on these transition adjustment revenues, hence it is appropriate to gross these transition adjustments up for this obligation that PGE will incur.

Q. Should you also gross-up the Schedule 129 transition adjustments that are applicable to Schedule 485 and 489?

A. Not necessarily. Because we spread the historically determined Schedule 129 transition adjustments to applicable schedules such that the revenue impact is zero, we do not propose to adjust the existing Schedule 129 transition adjustments that were determined in earlier enrollment periods. However, Schedule 129 transition adjustments calculated in the future should be grossed-up by the then applicable franchise fee revenue requirement percentage rate. This would achieve the desired consistency with Schedule 128. The Schedule 129 amounts that are grossed-up will be spread to applicable customers in the same manner as we do now.

Q. Please provide the proposed monthly prices for Schedule 85 and describe the customers to whom these prices apply.

A. We propose that Schedule 85 apply to all Large Nonresidential customers whose Facility Capacity demands are between 201 kW and 4,000 kW. Those customers whose facility capacity exceeds 4,000 kW take service under Schedule 89, which we discuss below. We base the individual charges on the results of the marginal cost study and subsequent ratespread, paying particular attention to appropriately pricing the cost differentials between secondary and primary delivery voltages. The prices differentiated by delivery voltage are below:

Table 5
Schedule 85 General Service 201-4,000 kW

Category	Secondary Price		Primary Price	
Basic Charge	$370.00	per customer per month	$390.00	per customer per month
Trans. & Related Services	$0.88	per kW peak Demand	$0.85	per kW peak Demand
Distribution Demand Charge	$2.05	per kW peak Demand	$1.99	per kW peak Demand
Facility Capacity Charge (First 200 kW)	$3.12	per kW Facility Capacity	$3.04	per kW Facility Capacity
Facility Capacity Charge (Over 200 kW)	$2.12	per kW Facility Capacity	$2.04	per kW Facility Capacity
System Usage Charge	1.94	mills per kWh	1.87	mills per kWh
COS Energy Charge On-peak	60.85	mills per kWh	59.28	mills per kWh
COS Energy Charge Off-peak	50.85	mills per kWh	49.28	mills per kWh

Q. Please describe how you developed the Schedule 85 prices.

A. The Schedule 85 **Basic Charges** differ by delivery voltage. For secondary service and primary voltage, we set the Basic Charges at $370.00 and $390.00 per month, respectively. These customer charges, subject to rounding, recover the full amount of the allocated marginal customer-related costs of the smaller Schedule 85 customers, therefore those customers who range from 201-1,000 kW. These customer charges combined with the declining block facilities charges help transition those Schedule 83 customers whose demand grows to exceed 200 kW. This pricing also provides for a better transition for those Schedule 85 customers whose demand exceeds 4,000 kW, thereby migrating to Schedule 89.

For Schedules 83, 85, and 89, we set the **Transmission & Related Service Charge** to $0.88 per kW for secondary service, and to $0.85 per kW for primary service; prices that are slightly higher than the allocated revenue requirements.

The **Distribution Charges** for Schedule 85 consist of a **Demand Charge** and a **Facility Capacity Charge**. For both secondary and primary voltage customers, we recover the costs associated with the 13 kV system through the Facility Capacity Charge. The difference between secondary and primary voltage Facility Capacity Charges reflect the difference in estimated peak demand losses for the respective delivery voltages. The facilities charge also recovers any over- or under-recovery of the other charges.

The **Demand Charges** of $2.05 and $1.99 for secondary and primary customers, respectively are set in conjunction with the demand charges for schedules 83 and 89 as discussed earlier. We calculate the demand charge difference based on the difference in peak demand losses of the respective delivery voltages.

Because several energy options are available to Schedules 85 and 585, we separately state the **System Usage Charge** which recovers franchise fees, Trojan Decommissioning costs, the Schedule 129 transition adjustment, and the CIO. We also use this charge for both Schedules 85 and 89 to capture the Schedule 129 transition adjustment and the generation fixed cost contributions of either returning or departing long-term direct access customers. The System Usage Charge is lower for both Schedules 485 and 585 for the reasons stated earlier in testimony.

We calculate the COS calculate the on the results of the generation allocations. We set the on-and off-peak differential at 10 mills/kWh, up from the current 7.57 mills/kWh. We calculate the energy price difference between the secondary and primary voltage customers based on the difference in embedded line losses.

Q. Please describe the Schedule 85 Energy Charge options.

A. The Schedule 85 energy price options are the same as those for Schedule 83 described above.

Q. Please provide the proposed monthly prices for Schedule 89 and describe the customers to whom these prices are applicable.

A. Schedule 89 applies to all Large Nonresidential customers whose Facility Capacity exceeds 4,000 kW. The Schedule 89 prices differentiated by delivery voltage are below:

Table 6
Schedule 89 General Service Greater than 4,000 kW

Category	Secondary	Primary	Subtransmission
Basic Charge	$4,850.00 per month	$4,460.00 per month	$5,130.00 per month
Transmission & Related Charge	$ 0.88 per on-peak kW	$0.85 per on-peak kW	$0.84 per on-peak kW
Facility Capacity Charge First 4,000 kW	$1.90 per kW Facility Capacity	$1.85 per kW Facility Capacity	$1.85 per kW Facility Capacity
Facility Capacity Charge Over 4,000 kW	$1.26 per kW Facility Capacity	$1.21 per kW Facility Capacity	$1.21 per kW Facility Capacity
Distribution Demand Charge	$2.05 per on-peak kW	$1.99 per on-peak kW	$1.12 per on-peak kW
System Usage Charge	1.62 mills per kWh	1.57 mills per kW	1.54 mills per kW
COS Energy Charge On-peak	57.81 mills per kWh	56.11 mills per kWh	55.37 mills per kWh
COS Energy Charge Off-peak	47.81 mills per kWh	46.11 mills per kWh	45.37 mills per kWh

Q. Please describe how you developed the Schedule 89 Charges.

A. We set the **Basic Charges** for secondary, primary and subtransmission voltage customers at 50% of the marginal-customer-related costs with any under-collection captured by the Facility Capacity Charges.

The **Transmission and Related Service Charge** is calculated in conjunction with Schedules 83 and 85 for the reasons previously discussed. Because this charge is less than the allocated costs, the Facility Capacity Charge recovers the remainder.

The **Distribution Demand Charge** is also calculated in conjunction with Schedules 83 and 85. Any under-collection of costs is recovered through the Facility Capacity Charge. For both secondary and primary voltage customers the distribution demand charge reflects the marginal cost of providing substations and shared subtransmission facilities, subject to the conjunctive pricing with other schedules referenced above. For customers served at subtransmission voltage who supply their own substation, the Distribution Demand Charge reflects the marginal cost of the shared subtransmission system, again subject to the conjunctive pricing with other rate schedules. It also reflects the cost per kW differential between connecting a customer of equal size with a 13 kV feeder or a feeder at 115 kV. This differential of nine cents/kW is added to the Distribution Demand Charge to equalize the Facility Capacity Charge for primary voltage and subtransmission voltage delivery. As with Schedule 85, we set the delivery voltage price differentials based on the peak demand loss differences of the respective delivery voltages.

The **Facility Capacity Charge** for Schedule 89 customers has two blocks; one for the first 4,000 kW, and the second for billing kW greater than 4,000 kW. The first block facilitates the migration of customers from Schedule 85, while the second block captures the remaining facilities-related revenue requirements of Schedule 89 customers. Both Facility Capacity Charge blocks reflect the peak demand loss difference between providing service at secondary or primary voltage service. As mentioned above, we set the Facility Capacity Charge for subtransmission voltage customers equal to that of primary voltage customers and flow any cost difference to the subtransmission voltage Demand Charge.

The **COS Energy Charge** option for Schedule 89 is on- and off-peak differentiated by delivery voltage. We set this differential at 10 mills/kWh, the same differential set for Schedule 85. A Daily Price option is also available similar to that described for Schedule 83. Customers who wish to pursue the Direct Access Energy Option will take service under Schedule 589. As with Schedules 83/583 and 85/585, Schedules 89 and 589 separately identify the System Usage Charge which is lower for direct access customers.

Q. Please describe the development of charges for the remaining rate schedules.

A. The remaining proposed rate schedules, with one exception, provide service to lighting and irrigation customers and are discussed below:

We structure **Schedule 15, Outdoor Area Lighting Standard Service** charges in the same manner as the current rate schedule. The Monthly Charge contains all of the allocated costs based on the specific kWh usage by luminaire. Schedule 515 provides this customer class with Direct Access Service charges.

Schedule 38, Large Nonresidential Optional Time-of-Day Standard Service is, as its name implies, an optional schedule that is applicable to customers whose facility capacity is between 31 and 200 kW. We propose the same monthly $25.00 Basic Charge for single- and three-phase service customers. We maintain the volumetric recovery of transmission and distribution costs and continue to differentiate the energy charges based on the on- and off-peak periods defined in Schedule 38.

Schedule 47, Irrigation and Drainage Pumping Small Nonresidential Standard Service, applies to Small Nonresidential customers whose demand does not exceed 30 kW. We increase the monthly Basic Charge to $30.00 per month for the six summer months only, and we retain the blocked Distribution Charge. Schedule 47 customers may take Direct Access Service under Schedule 532.

Schedule 49, Irrigation and Drainage Pumping Large Nonresidential Standard Service, is similar to Schedule 47, but applies to customers larger than 30 kW. We increase the Basic Charge to $40 per month, summer months only. Similar to Schedule 47, we continue to block the Distribution Charge. Schedule 549 states the Direct Access charges for these customers. These customers are also eligible for Direct Access Service on Schedules 583, 585, or 589.

Schedules 91/591 and 95/595, Street and Highway Lighting Standard Service, provides municipalities with outdoor lighting service. These schedules are similar in structure to Schedule 15. Each service-option monthly rate includes the applicable unbundled costs, based on the monthly kWh usage of the particular type of light. We discuss streetlights in more depth in Section IV.

Schedule 92, Traffic Signals Standard Service, is an energy-only rate for un-metered traffic control devices in systems with at least 50 intersections. We retain the energy-only nature of the rate.

Schedule 592, Traffic Signals Direct Access Service, provides the Direct Access-related energy-only based charge for this specialty service. Schedules 92/592 remain grandfathered services closed to additional governmental agencies.

Q. Why do you propose to consolidate Schedule 93 into Schedule 38?

A. We propose this rate schedule consolidation because Schedule 93 has a small amount of customers and associated revenues. It is not practical to maintain a separate schedule for these customers when they can be placed on an existing schedule that also recovers costs on a volumetric basis. Placing these Schedule 93 customers on Schedule 38 will provide them with bill savings that will be absorbed in whole by existing Schedule 38 customers. Hence, no other schedules will be negatively impacted, and arguably schedules other than Schedule 38 may be positively impacted because Schedule 93 has historically been subsidized by other rate schedules.

Q. Why and how do you limit the amount of increase to some rate schedules?

A. The pricing for Schedules 47 and 49 is established at rates that are significantly less than the cost to serve. If we were to price these schedules at cost, they would experience extremely large rate increases. We therefore propose to limit Schedules 47 and 49 to no more than a 17% percent base rate increase. Over time, we will gradually move these schedules closer to cost of service while gradually sending the appropriate price signal. We also propose to mitigate the percentage increase to Schedules 7 and 32 in the manner described earlier in testimony.

Q. Which schedules bear the costs of mitigation of the schedules mentioned above?

A. We propose that all schedules not receiving the CIO as a credit bear the mitigation burden with the exception of the lighting schedules 15 and 91. We exempt the lighting schedules because of the large increase for Schedule 15 and our desire to maintain the same volumetric charges for Schedules 15, 91, and 95.

Q. How do you implement the CIO mitigation?

A. We increase the System Usage Charges for Schedules 83, 85, and 89, and the distribution charges for Schedules 38 and 92 to offset the effect of the price mitigation efforts described above. Schedules receiving the CIO subsidy do so through their distribution charges. We also use the CIO to equalize the distribution charges for the outdoor lighting schedules 15, 91, and 95. PGE Exhibit 1503 shows the development of this offset.

IV. Streetlights

Q. Please describe the changes you propose in the pricing of Area Lights and Streetlights.

A. We propose the following changes:

1) Price the investment portion (poles and luminaires) of providing lighting service for Schedules 15 and 91 at marginal cost rather than at embedded cost.

2) Eliminate the embedded cost circuit charge for Schedules 15, 91, and 95.

3) Base the proposed test period lighting maintenance amounts on the most recent full re-lamping cycle, escalated for inflation.

Q. Why do you propose to price poles and luminaires at their respective marginal costs instead of at historical cost?

A. We propose this to better reflect the cost of providing lighting service. We have already incorporated marginal cost pricing for the luminaires specified in our current Schedule 95 Street and Highway Lighting New Technology. Pricing Schedules 15 and 91 luminaires and poles at marginal cost will provide for consistency across the lighting schedules. More importantly, it will also provide a better pricing signal to lighting customers and enable them to make more informed choices about what lighting technology they choose, and what combination of poles and luminaires they choose to own and maintain. Finally, marginal cost pricing provides a more equitable result to other customers because we offset the functionalized distribution revenue requirement by the amount of the lighting investment and maintenance.

Q. Why do you propose to eliminate the embedded circuit charge currently applicable to the lighting schedules?

A. We propose this because it provides for a more equitable and consistent allocation of distribution costs to the lighting customers. PGE and the City of Portland (COP) studied this issue extensively following UE 215, and both parties concluded that continued application of the embedded circuit charge would be inappropriate because it would be inconsistent with the manner in which other schedules are allocated distribution costs. Thus, we propose that the embedded circuit charge be replaced by a marginal cost analysis that incorporates the applicable Line Extension Allowance available to the lighting schedules.

Q. Did PGE and the COP submit a report that provides more detail about the circuit charge?

A. Yes. PGE filed this report with the OPUC on January 19, 2012, and sent it to the UE 215 Service List. The report is included in our work papers.

Q. Please describe the changes you propose to lighting maintenance?

A. We propose to base the test period lighting maintenance amount on the incurred maintenance amounts during PGE's most recent 5-year re-lamping cycle (2005-2009). More specifically, we express the historical maintenance amounts on a per-light basis, subtract the circuit maintenance amount consistent with the circuit charge discussion above, and then escalate this per-light maintenance figure for inflation. A further reduction is made for Light-Emitting Diode (LED) streetlights since, (1) their maintenance is significantly less than other streetlights, and (2) the years used in the most recent 5-year re-lamping cycle don't include LEDs. Following this, we allocate maintenance to each type of luminaire based on the marginal cost of maintenance study.

Q. How do the maintenance amounts calculated in the marginal cost study compare to the maintenance amounts calculated using the historical re-lamping cycle as a base?

A. The amounts are quite close; the total amount of maintenance we propose for the 2014 test period is approximately $40,000 lower than the amount calculated in the marginal cost study.

Q. In your opinion, will pricing Schedule 91 luminaires at marginal cost incent customers to convert to the more efficient LED technology available in Schedule 95?

A. Yes, it will provide more of an incentive for Schedule 91 Option A (PGE-owned) customers to convert to Schedule 95. Our proposal to price Schedule 91 at marginal cost, all else equal, raises the luminaire prices and makes Schedule 95 Option A luminaires, which are currently priced at marginal cost, more cost-effective relative to Schedule 91. Table 7 compares the proposed prices of common High-Pressure Sodium (HPS) cobrahead luminaires to manufacturer suggested equivalent LED luminaires.

Table 7
2014 Proposed Luminaire Prices (Fixed plus Energy)
Typical Cobrahead Luminaire

Watts	Option A HPS	Option A LED	Difference
70	$8.18	$4.75	($3.43)
100	$9.42	$5.15	($4.27)
150	$11.33	$5.67	($5.66)
200	$13.65	$6.65	($7.00)
250	$16.08	$8.80	($7.28)

Q. Did you forecast conversions to Schedule 95 LED streetlighting?

A. Yes. We forecast over 19,000 Option A streetlights converting from existing Schedule 91 to Schedule 95 luminaires using the average count in 2014. However, we underestimated the energy for Schedule 95 in the load forecast and will update the load forecast consistent with the Schedule 95 estimated conversion counts in our subsequent update.

Q. Do you provide a summary exhibit of the proposed pole and luminaire prices?

A. Yes. This summary is provided in PGE Exhibit 1505.

V. UE 215 Stipulation Follow-Up

Q. What is the purpose of this portion of your testimony?

A. The purpose of this portion of our testimony is to discuss our follow-up efforts related to the UE 215 PGE/COP Stipulation in UE 215.

Q. With respect to this proceeding, what did the Stipulation specify?

A. The Stipulation specified that in PGE's next general rate case, PGE would discuss the following rate design changes:

- On-peak generation demand charges for Schedules 83, 85, and 89.
- Time-of Use energy charges for Schedule 83.
- Seasonal or monthly differentiation of generation demand and energy charges for Schedules 83, 85, and 89.

Q. Do you propose to implement TOU energy charges for Schedule 83 in 2014?

A. Yes. To better reflect cost causation and to provide customers with more appropriate price signals, we propose that Schedule 83 include mandatory TOU energy prices with a modest on- and off-peak differential of 7 mills per kWh. This modest differential should help the approximately 11,000 Schedule 83 accounts become accustomed to TOU pricing without incurring large bill impacts.

Q. Do you propose to implement seasonal or monthly differentiation of generation demand and energy charges for Schedules 83, 85, and 89 in 2014?

A. No. There is no strong economic reason to differentiate PGE's energy prices, either on a seasonal or on a monthly basis.

Q. Please specify why seasonal or monthly differentiated energy pricing is not warranted for PGE.

A. Using historical Mid-Columbia hub prices as a basis, the only season that is consistently different from the other seasons is the spring, when regional hydro production generally peaks and prices are lower than during other seasons. In some years, Mid-Columbia prices have been higher during the winter, and in other years prices have been higher in the summer. Other than the spring, there is no clear pattern that indicates a strong basis for distinct seasons.

Q. Since there is not a clear basis for distinct seasons, should PGE propose mandatory monthly differentiated COS energy prices to Schedules 83, 85, and 89?

A. No. PGE already offers this in effect on a voluntary basis to Schedule 83, 85, and 89 customers through its Daily Price Option.

Q. Are there complications associated with changing prices as frequently as monthly?

A. Yes, there are numerous complications. Because of cycle billing, a customer's bill typically covers usage in two calendar months. Monthly rates would require prorating the associated charges. Customers could easily become confused about their monthly bills and would likely increase the frequency of calls to PGE because the monthly prorated bills would have double line items each month representing the two calendar months. This higher call frequency could require increases in staffing and costs. If applied to all customers, these monthly prorated bills would likely have significant impacts to the overnight batch processing of bills, lengthening the process such that the customer service information system may not be available to the customer service representatives in the morning.

Q. What do you conclude about seasonal pricing for Schedules 83, 85, and 89?

A. We conclude that mandatory seasonal pricing for these schedules is not warranted due to the lack of a strong economic basis for seasonal pricing and the complications associated with monthly differentiated pricing. Furthermore, Schedules 83, 85, and 89 have energy pricing options available to them that will allow them to achieve seasonal or monthly pricing.

Q. Have you performed an analysis of generation demand charges for Schedules 83, 85, and 89?

A. Yes. PGE Exhibit 1506 contains the detailed analysis of various possibilities for a generation demand charge.

Q. In general, what are some of the positive and negative aspects of incorporating a generation demand charge into the structure of commercial and industrial rate schedules?

A. Proponents state that generation demand charges provide a stronger price signal to customers and serve as a reminder that generation capacity is expensive. The proponents also state that generation demand charges appropriately benefit the higher load factor customers who use generation assets more efficiently relative to volumetric charges. Hence, intra-class cross-subsidies are avoided or mitigated.

Opponents of generation demand charges point out that recovering capacity costs related to costs incurred during coincident peak periods on a non-coincident peak basis for each customer is illogical because the individual non-coincident peaks may not be well aligned with the coincident peak periods. Furthermore, opponents point out that once a particular customer has consumed at their peak level during the monthly billing cycle, they no longer have an incentive to change their behavior for the remainder of the billing cycle. Instead of imposing generation demand charges on a non-coincident peak basis, it may be preferable to time-differentiate volumetric prices to provide a constant reminder to customers that capacity and energy are more expensive during certain times of the day.

Q. Could implementing generation demand charges for Schedule 83, 85, and 89 complicate the existing nonresidential rate structure?

A. Absolutely. We would likely have to also implement generation demand charges for Schedules 583, 585, and 589 as well in order to accommodate the short-term direct access customers in a non-discriminatory manner.

Q. Before discussing PGE Exhibit 1506, could you please provide some background on how generation revenue requirements are allocated to the respective schedules and how a generation demand charge might recover the capacity portion of those allocated generation costs?

A. Yes. To allocate the generation revenue requirement to the individual rate schedules PGE uses a "proxy peaker" marginal cost methodology combined with a 4-CP (January, July, August, and December) allocator. From this marginal cost methodology, each rate schedule is allocated a portion of the generation revenue requirement based on their capacity and energy marginal costs. Generally, the cost recovery mechanism for allocated capacity costs is a generation demand charge based on each customer's individual peak load during the monthly billing cycle.

Q. Can a generation demand charge produce anomalous results?

A. Yes. This is so because the generation capacity allocator is based on class contribution to system peak loads during a limited number of hours, while the cost recovery mechanism, the generation demand charge is based on each individual customer's non-coincident peak in each monthly billing cycle. If the analyst is not careful in designing demand and energy prices for each schedule, the result may be demand and energy prices that defy intuitive sense. To help illustrate this, below is a table of the proposed energy charges by schedule and delivery voltage for Schedules 83, 85, and 89 expressed in mills/kWh:

Table 8
Energy Charges by Schedule (mills/kWh)

Schedule	On-peak Energy	Off-peak Energy
Schedule 83	61.78	54.78
Schedule 85 Secondary	60.85	50.85
Schedule 85 Primary	59.28	49.28
Schedule 89 Secondary	57.81	47.81
Schedule 89 Primary	56.11	46.11
Schedule 89 Subtransmission	55.37	45.37

As one can clearly see from the table above, a generation allocation method partially based on capacity considerations, coupled with volumetric cost recovery results in lower energy charges for the larger rate schedules. This is due primarily to the flatter load shapes of the larger rate schedules. However, as pointed out below, the introduction of a generation demand charge can disrupt this intuitive result.

Q. Please discuss the analysis performed on pages 1 and 2 of PGE Exhibit 1506.

A. Pages 1 and 2 demonstrate the prices that can occur if one blindly applies generation cost allocations; again, generation cost allocations partially based on class contribution to system peak with monthly individual customer non-coincident peak billing determinants. In this example, the generation demand charges are set for each rate schedule to recover all of the allocated generation capacity costs, and the energy charges are set to recover the energy allocations. The calculated prices demonstrate the counterintuitive results of inappropriate rate design. For example, the generation demand charges for Schedule 85 are approximately $2.00 *lower* than the demand charges for Schedule 89. Hence, a customer on Schedule 89 would pay more for energy charges than they would if they were billed on Schedule 85. Clearly, a rate design that results in higher generation charges for customers with flatter load shapes is sub-optimal.

Q. What should be taken into account when performing rate design that incorporates generation demand charges?

A. At a minimum, designing rates should reflect the point at which the demand and energy charges equilibrate for the rate schedules, and incorporate this information into the rate design across the continuum of applicable rate schedules. The point at which demand and energy charges equilibrate for different rates schedules is referred to as the "crossover" point. Below, we discuss applications of generation demand charges that incorporate crossover analysis.

Q. Please describe how you incorporated a crossover analysis for schedules 83, 85, and 89.

A. We set the generation demand charge at the crossover point of $3.17 dollars per kW-month, differentiated by delivery voltage, and then allowed the on- and off-peak energy charges to recover the remaining generation revenue requirements for each of the three rate schedules. This analysis is shown on pages 3 and 4 of PGE Exhibit 1506.

Q. Did you perform a crossover analysis that excludes Schedule 83, therefore one that includes only Schedules 85 and 89?

A. Yes. This analysis is presented on pages 5 and 6 of PGE Exhibit 1506. In this case, the crossover point is at $3.15 per kW-month differentiated by delivery voltage. This is approximately 45% and 35% of the allocated capacity costs for Schedules 85 and 89, respectively.

Q. Did you explore any other rate design alternatives that include generation demand charges?

A. Yes. We analyzed a case where the generation allocations for Schedules 85 and 89 are combined and the generation demand charge of $7.67 fully recovers the combined capacity allocations. The result of this case, combining the allocations of the two rate schedules and then performing rate design, results in Schedule 85 customers as a whole paying $3.4 million more than they would otherwise. Schedule 89 customers benefit by the same amount that Schedule 85 customers are burdened. The analysis is presented on pages 7 and 8 of PGE Exhibit 1506.

Q. Do you propose to implement a generation demand charge in this docket?

A. No. The current volumetric recovery of generation costs is preferable to implementing a generation demand charge. Volumetric charges insure that the resulting energy prices reflect intuitive sense, they are administratively simple, and they are consistent with the competitive supply options available to applicable customers.

Q. Are there ways other than generation demand charges to address intra-class subsidies?

A. Yes. An effective manner in which to address intra-class subsidies is by raising customer charges to reflect costs. As we noted above, we propose higher customer charges for Schedule 83, 85 and 89, but these proposed customer charges are still below cost, particularly for Schedules 83 and 89. We hope to gradually increase customer charges for these large nonresidential schedules over time to better reflect cost, and hence to better address intra-class subsidies.

VI. Other Rate Schedule Changes

Q. Do you propose to continue Schedule 123, Decoupling Adjustment?

A. Yes. We propose to make Schedule 123 an ongoing decoupling mechanism that continues to align customer and PGE interests in pursuing energy efficiency. The current Schedule 123 was first implemented in 2009 with an initial two year term. In UE 215, parties stipulated to extending the existing decoupling mechanism for another three years. In order for PGE to continue the mechanism, PGE must request an extension either by separate filing, or as part of a general rate filing. With this filing we are requesting the permanent extension of Schedule 123.

Q. Have the parties to the stipulation in UE 215 retained an independent consultant to evaluate the PGE decoupling mechanism?

A. Yes. We have retained Christensen Associates and we anticipate that the evaluation will be completed before June 1, 2013. In this manner, the Commission and parties to this proceeding will be better informed regarding the merits of the current decoupling mechanism and how it may be improved upon. The investigation of the evaluation of decoupling mechanism will be processed through Docket UM 1644.

Q. Please describe the limited changes you propose to Schedule 123.

A. First, we propose to update the Sales Normalization Adjustment (SNA) reference prices consistent with changes in unit fixed and variable charges for both Schedules 7 and 32.

Second, we propose to similarly update the Lost Revenue Recovery Adjustment (LRRA) for the other applicable schedules.

Third, we propose to continue the LRRA for LED streetlights. Specifically, we propose that the LRRA apply to the differences in actual LED conversions from those presumed in setting base rates. This is comparable to the manner in which the LRRA is applied to the differences in energy efficiency savings.

Finally, we propose to remove Special Condition 4 in order to allow Schedule 123 to continue beyond the pilot termination date of December 31, 2013.

Q. Do you propose other procedural changes to Schedule 123?

A. Yes. The Schedule 123 Decoupling Adjustment process requires that PGE file by April 1, the proposed Schedule 123 prices, with an effective date of June 1. Commencing in 2014, we propose to file the 2013 decoupling results by November 1, 2014 for prices effective January 1, 2015.

Q. Why do you propose this timing change?

A. We propose this change to better match the filing of the decoupling results with the Energy Trust of Oregon's (ETO) Annual Report to the OPUC. In previous years, we have had to supplement our April 1 filings because the ETO's Annual Report to the OPUC detailing the energy efficiency savings attributable to Schedule 109 funding was not complete. In addition, we propose this timing change in order to eliminate the only remaining mid-year price change. The current filing requirements were meant to coincide with the mandated timing of Schedule 140 Income Tax Adjustment. Because this schedule is no longer applicable, it is preferable to change the timing of the Schedule 123 to coincide with the timing of our other price changes on January 1 of each year.

Q. What changes do you propose to Schedules 125 and 126?

A. We propose to add language regarding the definition of Net Variable Power Costs (NVPC) and the inputs to NVPC that may be updated annually. These proposed changes are discussed in PGE Exhibit 400.

Q. What changes do you propose to Schedule 145?

A. We propose to change the purpose of Schedule 145 to solely reflect the cost recovery of decommissioning Boardman. Currently, Schedule 145 recovers not only the Boardman decommissioning costs, but also the accelerated depreciation/amortization effects of retiring the plant in 2020. This change in purpose is consistent with the provisions of OPUC Order No. 11-242.

Q. What is the amount of the 2014 proposed Schedule 145 collection?

A. Approximately $2.3 million.

VII. Qualifications

Q. Mr. Cody, please state your educational background and qualifications.

A. I received a Bachelor of Arts degree and a Master of Science degree from Portland State University. Both degrees were in Economics. The Master of Science degree has a concentration in econometrics and industrial organization.

Since joining PGE in 1996, I have worked as an analyst in the Rates and Regulatory Affairs Department. My duties at PGE have focused on cost of capital estimation, marginal cost of service, rate spread and rate design.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
1501	Proposed Tariff Changes
1502	Estimated Impact of Proposed Changes on Customers
1503	Rate Design
1504	Allocation of Costs to Customer Classes
1505	Streetlight and Area Lights
1506	Generation Demand Charge

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	Table of Contents, Rules and Regulations	
	Standard Service Schedules	
7	Residential Service	
12	Residential Critical Peak Pricing Pilot	
15	Outdoor Area Lighting Standard Service (Cost of Service)	
32	Small Nonresidential Standard Service	
38	Large Nonresidential Optional Time-of-Day Standard Service (Cost of Service)	
47	Small Nonresidential Irrigation and Drainage Pumping Standard Service (Cost of Service)	
49	Large Nonresidential Irrigation and Drainage Pumping Standard Service (Cost of Service)	
54	Large Nonresidential Tradable Renewable Credits Rider	
75	Partial Requirements Service	
76R	Partial Requirements Economic Replacement Power Rider	
77	Firm Load Reduction Pilot Program	
81	Nonresidential Emergency Default Service	
83	Large Nonresidential Standard Service (31 – 200 kW)	
85	Large Nonresidential Standard Service (201 – 4,000 kW)	(C)
86	Nonresidential Demand Buy Back Rider	

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92	Traffic Signals (No New Service) Standard Service (Cost of Service)	(D)
95	Street and Highway Lighting New Technology (Cost of Service)	
99	Special Contracts	
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100	Summary of Applicable Adjustments	
102	Regional Power Act Exchange Credit	
105	Regulatory Adjustments	
106	Multnomah County Business Income Tax Recovery	
108	Public Purpose Charge	
109	Energy Efficiency Funding Adjustment	
110	Energy Efficiency Customer Service	
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123	Decoupling Adjustment	

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128	Short-Term Transition Adjustment	
129	Long-Term Transition Cost Adjustment	
135	Demand Response Cost Recovery Mechanism	
137	Customer-Owned Solar Payment Option Cost Recovery Mechanism	
142	Underground Conversion Cost Recovery Adjustment	
145	Boardman Power Plant Decomissioning Adjustment	(C)
	Small Power Production	
200	Dispatchable Standby Generation	
203	Net Metering Service	
215	Solar Payment Option Pilot Small Systems (10 kW or Less)	
216	Solar Payment Option Pilot Medium Systems (Greater Than 10 kW to 100 kW)	
217	Solar Payment Option Pilot Large Systems (Greater Than 100 kW to 500 kW)	
	Schedules Summarizing Other Charges	
300	Charges as defined by the Rules and Regulations and Miscellaneous Charges	
310	Deposits for Residential Service	
320	Meter Information Services	
330	Advanced Metering Infrastructure (AMI Project) Meter Base Repair Program	
344	Oregon Electric Vehicle (EV) Highway Pilot Rider	
338	On-Bill Loan Repayment Service Pilot – Portland Clean Energy Fund Program (No New Service)	
339	On-Bill Loan Repayment Service –Clean Energy Works of Oregon Program	
	Promotional Concessions	
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	Transmission Access Service	
485	Large Nonresidential Cost of Service Opt-Out (201 – 4,000 kW)	(C)
489	Large Nonresidential Cost of Service Opt-Out (>4,000 kW)	(C)
	Direct Access Schedules	
515	Outdoor Area Lighting Direct Access Service	
532	Small Nonresidential Direct Access Service	
538	Large Nonresidential Optional Time-of-Day Direct Access Service	
549	Large Nonresidential Irrigation and Drainage Pumping Direct Access Service	
575	Partial Requirements Service Direct Access Service	
576R	Economic Replacement Power Rider Direct Access Service	
583	Large Nonresidential Direct Access Service (31 – 200 kW)	
585	Large Nonresidential Direct Access Service (201 – 4,000 kW)	(C)
589	Large Nonresidential Direct Access Service (>4,000 kW)	(C)
591	Street and Highway Lighting Direct Access Service	
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595	Street and Highway Lighting New Technology Direct Access Service	
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RATE SCHEDULES (Concluded)

SCHEDULE 7
RESIDENTIAL SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Residential Customers.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge			
Single Phase Service	$10.00		(I)
Three Phase Service	$10.00		(R)
Transmission and Related Services Charge	0.299	¢ per kWh	(I)
Distribution Charge	3.962	¢ per kWh	(I)
Energy Charge Options			
Standard Service			
First 1,000 kWh	6.434	¢ per kWh	(R)
Over 1,000 kWh	7.156	¢ per kWh	
or			
Time-of-Use (TOU) Portfolio (Whole Premises or Electric Vehicle (EV) TOU) (Enrollment is necessary)			
On-Peak Period	12.739	¢ per kWh	
Mid-Peak Period	7.156	¢ per kWh	
Off-Peak Period	4.247	¢ per kWh	(R)
First 1,000 kWh block adjustment**	(0.722)	¢ per kWh	

* See Schedule 100 for applicable adjustments.
** Not applicable to separately metered Electric Vehicle (EV) TOU option.

SCHEDULE 15
OUTDOOR AREA LIGHTING
STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Customers for outdoor area lighting.

CHARACTER OF SERVICE

Lighting services, which consist of the provision of Company-owned luminaires mounted on Company-owned poles, in accordance with Company specifications as to equipment, installation, maintenance and operation.

The Company will replace lamps on a scheduled basis. Subject to the Company's operating schedules and requirements, the Company will replace individual burned-out lamps as soon as reasonably possible after the Customer notifies the Company of the burn-out.

MONTHLY RATE

Included in the service rates for each installed luminaire are the following pricing components:

Transmission and Related Services Charge	0.182	¢ per kWh	**(R)**
Distribution Charge	4.682	¢ per kWh	**(I)**
Cost of Service Energy Charge	5.078	¢ per kWh	**(R)**

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)

Rates for Area Lighting

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate [(1)] Per Luminaire	
Cobrahead					
Mercury Vapor	175	7,000	66	$12.78 [(2)]	(I)
	400	21,000	147	21.10 [(2)]	(R)
	1,000	55,000	374	44.46 [(2)]	(I)
HPS	70	6,300	30	9.32 [(2)]	
	100	9,500	43	10.56	
	150	16,000	62	12.47	
	200	22,000	79	14.32	
	250	29,000	102	16.76	
	310	37,000	124	19.34 [(2)]	
	400	50,000	163	23.21	
Flood, HPS	100	9,500	43	10.59 [(2)]	
	200	22,000	79	15.22 [(2)]	
	250	29,000	102	17.55	
	400	50,000	163	23.60	
Shoebox, HPS (bronze color, flat lens or drop lens, multi-volt)	70	6,300	30	10.77	
	100	9,500	43	12.25	
	150	16,500	62	14.44	
Special Acorn Type, HPS	100	9,500	43	15.23	
HADCO Victorian, HPS	150	16,500	62	17.12	
	200	22,000	79	19.58	
	250	29,000	102	21.89	
Early American Post-Top, HPS Black	100	9,500	43	11.33	(I)

(1) See Schedule 100 for applicable adjustments.
(2) No new service.

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)
Rates for Area Lighting (Continued)

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate Per Luminaire[1]	
Special Types					
Cobrahead, Metal Halide	150	10,000	60	$12.90	(R)
	175	12,000	71	14.28	(I)
Flood, Metal Halide	350	30,000	139	22.65	
	400	40,000	156	23.13	
Flood, HPS	750	105,000	285	39.26	
HADCO Independence, HPS	100	9,500	43	15.36	
	150	16,000	62	16.91	
HADCO Capitol Acorn, HPS	100	9,500	43	19.34	
	150	16,000	62	21.28	
	200	22,000	79	22.84	
	250	29,000	102	25.14	
HADCO Techtra, HPS	100	9,500	43	24.48	
	150	16,000	62	26.02	(I)
	250	29,000	102	29.35	(R)
HADCO Westbrooke, HPS	70	6,300	30	16.99	(I)
	100	9,500	43	18.04	
	150	16,000	62	19.94	
	200	22,000	79	21.92	
	250	29,000	102	24.09	
KIM Archetype, HPS	250	29,000	102	27.08	
	400	50,000	163	27.95	
Holophane Mongoose, HPS	150	16,000	62	17.60	
	250	29,000	102	20.88	(I)
					(D)

(1) See Schedule 100 for applicable adjustments.
(2) No new service.

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)

Type of Pole Rates for Area Light Poles[1]	Pole Length (feet)	Monthly Rate Per Pole	
Wood, Standard	35 or less	$7.40	(I) (C)
	40 to 55	9.70	
Wood, Painted for Underground	35 or less	7.40 [2]	
Wood, Curved Laminated	30 or less	9.19 [2]	
Aluminum, Regular	16	8.86	
	25	14.70	
	30	15.89	
	35	19.02	
Aluminum, Fluted Ornamental	14	12.99	
Aluminum Davit	25	13.60	
	30	14.60	
	35	15.97	
	40	21.68	
Aluminum Double Davit	30	21.58	(I)
Aluminum, HADCO, Fluted Ornamental	16	13.28	(R)
Aluminum, HADCO, Non-fluted Techtra Ornamental	18	25.57	(I)
Concrete Ameron Post-Top	25	25.51	(R)
Fiberglass Fluted Ornamental; Black	14	15.70	(I)
Fiberglass, Regular			
Black	20	6.51	
Gray or Bronze	30	11.07	
Other Colors (as available)	35	9.53	
Fiberglass, Anchor Base Gray	35	17.45	
Fiberglass, Direct Bury with Shroud	18	10.50	(I)

(1) No pole charge for luminaires placed on existing Company-owned distribution poles.
(2) No new service.

SCHEDULE 32
SMALL NONRESIDENTIAL
STANDARD SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Small Nonresidential Customers. A Small Nonresidential Customer is a Customer that has not exceeded 30 kW more than once within the preceding 13 months, or with seven months or less of service has not exceeded 30 kW.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge			
Single Phase Service	$14.00		(I)
Three Phase Service	$18.00		
Transmission and Related Services Charge	0.248	¢ per kWh	
Distribution Charge			
First 5,000 kWh	4.401	¢ per kWh	
Over 5,000 kWh	0.833	¢ per kWh	(I)
Energy Charge Options			
Standard Service	6.024	¢ per kWh	(R)
or			
Time-of-Use (TOU) Portfolio (enrollment is necessary)			
On-Peak Period	10.644	¢ per kWh	
Mid-Peak Period	6.024	¢ per kWh	
Off-Peak Period	3.550	¢ per kWh	(R)

* See Schedule 100 for applicable adjustments.

SCHEDULE 32 (Continued)

DAILY PRICE

The Daily Price, applicable with Direct Access Service, is available to those Customers who were served under Schedule 532 and subsequently returned to this schedule before meeting the minimum term requirement of Schedule 532. The Customer will be charged the Daily Price charge of this schedule until the term requirement of Schedule 532 is met.

The Daily Price will consist of:

- the Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Firm Index)
- plus 0.294 ¢ per kWh for wheeling (I)
- times a loss adjustment factor of 1.0820

If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported.

Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

PLUG-IN ELECTRIC VEHICLE (EV) TOU OPTION

A small Nonresidential Customer wishing to charge EV's may do so either as part of an integrated service (Standard service or TOU service) or as a separately metered service billed under the TOU option. In such cases, the applicable Basic, Transmission and Related Services, and Distribution charges will apply to the separately metered service as will all other adjustments applied to this schedule. Renewable Portfolio Options are also available under this EV option.

If the Customer chooses separately metered service for EV charging, the service shall be used for the sole and exclusive purpose of all EV charging. The Customer, at its expense, will install all necessary and required equipment to accommodate the second metered service at the premises. Such service must be metered with a network meter as defined in Rule B (30) for the purpose of load research, and to collect and analyze data to characterize electric vehicle use in diverse geographic dynamics and evaluate the effectiveness of the charging station infrastructure.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 38
LARGE NONRESIDENTIAL OPTIONAL TIME-OF-DAY
STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

This optional schedule is applicable to Large Nonresidential Customers: 1) served at Secondary voltage with a monthly Demand that does not exceed 200 kW more than once in the preceding 13 months; or 2) who were receiving service on Schedule 38 as of December 31, 2006.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge			
Single Phase Service	$25.00		(I)
Three Phase Service	$25.00		
Transmission and Related Services Charge	0.235	¢ per kWh	(I)
Distribution Charge	6.323	¢ per kWh	(I)
Energy Charge*			
On-Peak Period	6.462	¢ per kWh	(R)
Off-Peak Period	5.462	¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.
** On-peak Period is Monday-Friday, 7:00 a.m. to 8:00 p.m. off-peak Period is Monday-Friday, 8:00 p.m. to 7:00 a.m.; and all day Saturday and Sunday.

MINIMUM CHARGE

The Minimum Charge will be the Basic Charge. In Addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge if necessary, to justify the Company's investment in service facilities.

REACTIVE DEMAND

In addition to the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

SCHEDULE 38 (Continued)

DIRECT ACCESS DEFAULT SERVICE

A Customer returning to Schedule 38 service before completing the term of service specified in Schedule 538, must be billed at the Daily Price for the remainder of the term. This provision does not eliminate the requirement to receive service on Schedule 81 when notice is insufficient. The Daily Price under this schedule is as follows:

Daily Price Option - The Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Firm Index) plus 0.294¢ per kWh for wheeling, plus losses. If prices (I) are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported. To begin service under this option, the Customer will notify the Company by the close of the November Election Window or for eligible Customers, the close of a Balance-of-Year Election Window.

Losses will be included by multiplying the above applicable Energy Charge Option by the following adjustment factors:

Secondary Delivery Voltage	1.0820

PLUG-IN ELECTRIC VEHICLE (EV) TIME OF DAY OPTION

A large Nonresidential Customer wishing to charge EV's may do so either as part of an integrated service or as a separately metered service billed under the TOU Option. In such cases, the applicable Basic, Transmission and Related Services, and Distribution charges will apply to the separately metered service as will all other adjustments applied to this schedule.

If the Customer chooses separately metered service for EV charging, the service shall be used for the sole and exclusive purpose of all EV charging. The Customer, at its expense, will install all necessary and required equipment to accommodate the second metered service at the premises. Such service must be metered with a network meter as defined in Rule B (30) for the purpose of load research, and to collect and analyze data to characterize electric vehicle use in diverse geographic dynamics and evaluate the effectiveness of the charging station infrastructure.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 47
SMALL NONRESIDENTIAL IRRIGATION AND DRAINAGE PUMPING STANDARD SERVICE (COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Small Nonresidential Customers for irrigation and drainage pumping; may include other incidental service if an additional meter would otherwise be required. A Small Nonresidential Customer is a Customer that has not exceeded 30 kW more than once within the preceding 13 months, or with seven months or less of service has not exceeded 30 kW.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge			
Summer Months**	$30.00		(I)
Winter Months**	No Charge		
Transmission and Related Services Charge	0.391	¢ per kWh	
Distribution Charge			
First 50 kWh per kW of Demand***	6.598	¢ per kWh	
Over 50 kWh per kW of Demand	4.598	¢ per kWh	
Energy Charge	7.399	¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.
** Summer Months and Winter Months commence with meter readings as defined in Rule B.
*** For billing purposes, the Demand will not be less than 10 kW.

MINIMUM CHARGE

The Minimum Charge will be the Basic Charge. In addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge if necessary, to justify the Company's investment in service facilities.

SCHEDULE 49
LARGE NONRESIDENTIAL
IRRIGATION AND DRAINAGE PUMPING
STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers for irrigation and drainage pumping; may include other incidental service if an additional meter would otherwise be required. A Large Nonresidential Customer is defined as having a monthly Demand exceeding 30 kW at least twice within the preceding 13 months, or with seven months or less of service having exceeding 30 kW once.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge			
Summer Months**	$35.00		(I)
Winter Months**	No Charge		
Transmission and Related Services Charge	0.382	¢ per kWh	
Distribution Charge			
First 50 kWh per kW of Demand***	4.443	¢ per kWh	
Over 50 kWh per kW of Demand	2.443	¢ per kWh	
Energy Charge	7.233	¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.
** Summer Months and Winter Months commence with meter readings as defined in Rule B.
*** For billing purposes, the Demand will not be less than 30 kW.

MINIMUM CHARGE

The Minimum Charge will be the Basic Charge. In addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge if necessary, to justify the Company's investment in service facilities.

SCHEDULE 75
PARTIAL REQUIREMENTS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers supplying all or some portion of their load by self-generation operating on a regular basis, where the self-generation has a total nameplate rating of 2 MW or greater. A Large Nonresidential Customer is a Customer that has exceeded 30 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 30 kW.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Point of Delivery (POD)*:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge	$4,850.00	$4,460.00	$5,130.00	(I)
Transmission and Related Services Charge				
per kW of monthly On-Peak Demand	$0.88	$0.85	$0.84	
Distribution Charges				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.90	$1.85	$1.85	
Over 4,000 kW	$1.26	$1.21	$1.21	
per kW of monthly On-Peak Demand	$2.05	$1.99	$1.12	(I)
Generation Contingency Reserves Charges				
Spinning Reserves				
per kW of Reserved Capacity > 2,000 kW	$0.234	$0.234	$0.234	
Supplemental Reserves				
per kW of Reserved Capacity > 2,000 kW	$0.234	$0.234	$0.234	
System Usage Charge				
per kWh	0.162 ¢	0.157 ¢	0.154 ¢	(R)
Energy Charge				
per kWh	See Energy Charge Below			

* See Schedule 100 for applicable adjustments.

SCHEDULE 75 (Continued)

ENERGY CHARGE (Continued)
Baseline Energy (Continued)

If other than the typical operations are used to determine Baseline Energy, the Customer and the Company must agree on the Baseline Energy before the Customer may take service under this schedule. The Company may require use of an alternate method to determine the Baseline Energy when the Customer's usage not normally supplied by its generator is highly variable.

Baseline Energy will be charged at the applicable Energy Charge, including adjustments, under Schedule 89. All Energy Charge options included in Schedule 89 are available to the Customer on Schedule 75 based on the terms and conditions under Schedule 89. For Energy supplied in excess of Baseline Energy, the Scheduled Maintenance Energy and/or Unscheduled Energy charges will apply except for Energy supplied pursuant to Schedule 76R.

Any Energy Charge option for Baseline Energy selected by a Customer will remain in effect and continue to be the default option until the Customer has given the required notice to change the applicable Energy Charge Option. To change options, Customers must give notice as specified for that option and must complete the specified term of their current option. The Cost of Service Option will be the default for Customers or new Customers who have not selected another option or Direct Access Service.

Scheduled Maintenance Energy

Scheduled Maintenance Energy is Energy prescheduled for delivery, up to 744 hours per calendar year, to serve the Customer's load normally served by the Customer's own generation (i.e. above Baseline Energy). Scheduled Maintenance must be prescheduled at least one month (30 days) before delivery for a time period mutually agreeable to the Company and the Customer.

When the Customer preschedules Energy for an entire calendar month, the Customer may choose that the Scheduled Maintenance Energy Charge be either the Monthly Fixed or Daily Price Energy Charge Option, including adjustments as identified in Schedule 100 and notice requirements as described under Schedule 89. When the Customer preschedules Energy for less than an entire month, the Scheduled Maintenance Energy will be charged at the Daily Price Energy Option, including adjustments, under Schedule 89.

Unscheduled Energy

Any Electricity provided to the Customer that does not qualify as Baseline Energy or Scheduled Maintenance Energy will be Unscheduled Energy and priced at an Hourly Rate consisting of the Dow Jones Mid-Columbia Hourly Firm Electricity Price Index (DJ-Mid-C Hourly Firm Index) plus 0.294¢ per kWh for wheeling, a 0.300¢ per kWh recovery factor, **(I)**
plus losses.

SCHEDULE 76R
PARTIAL REQUIREMENTS
ECONOMIC REPLACEMENT POWER RIDER

PURPOSE

To provide Customers served on Schedule 75 with the option of purchasing Energy from the Company to replace some, or all, of the Customer's on-site generation when the Customer deems it is more economically beneficial than self generating.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers served on Schedule 75.

MONTHY RATE

The following charges are in addition to applicable charges under Schedule 75:*

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Transmission and Related Services Charge per kW of Daily Economic Replacement Power (ERP) On-Peak Demand per day	$0.034	$0.033	$0.033	(I)
Daily ERP Demand Charge per kW of Daily ERP Demand during On-Peak hours per day**	$0.080	$0.078	$0.044	(I)
System Usage Charge per kWh of ERP	0.162 ¢	0.157 ¢	0.154 ¢	(R)
Transaction Fee per Energy Needs Forecast (ENF)	$50.00	$50.00	$50.00	
Energy Charge* per kWh of ERP	See below for ERP Pricing			

* See Schedule 100 for applicable adjustments.

** Peak hours (also called heavy load hours "HLH") are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours (also called light load hours "LLH") are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

SCHEDULE 76R (Continued)

ENF AND ERP (Continued)
ERP Supply Options (Continued)
ENF Options for ERP (Continued)

The Daily ENF pre-scheduling protocols will conform to the standard practices, applicable definitions, requirements and schedules of the WECC. Pre-Schedule Day means the trading day immediately preceding the day of delivery consistent with WECC practices for Saturday, Sunday, Monday or holiday deliveries.

ERP Pricing

The following ERP Energy Charges are applied to the applicable hourly ENF and summed for the hours for the monthly billing:

Short-Notice ERP: The Short Notice ERP Energy Charge will be an Hourly Rate consisting of the Dow Jones Mid-Columbia Hourly Price Index (DJ-Mid-C Hourly Index) plus a 5% adder, which will not be less than 0.15¢ per kWh, plus 0.294¢ per kWh for wheeling, plus losses. If prices are not reported for a particular hour or hours, the average of the immediately preceding and following reported hours' prices within on- or off-peak periods, as applicable, will determine the price for the non-reported period. Prices reported with no transaction volume or as survey-based will be considered reported. (I)

Daily ERP: The Daily ERP Energy Charge will be determined in accordance with a commodity energy price quote from the Company accepted by the Customer plus a 5% adder, which will not be less than 0.15¢ per kWh, plus 0.294¢ per kWh for wheeling, plus losses. Customer will communicate with PGE between hour 0615 and 0625 to receive the PGE commodity energy price quote based on the customer's submitted ENF for the day of delivery. Customer will state acceptance of quote within 5 minutes of receipt of quote from the Company. The quote may incorporate reasonable premiums to reflect the additional cost of ENF amounts that are in nonstandard block sizes (i.e., other than multiples of 25 MW) and such premium will not be separately stated. The methods to communicate and the times to receive information and quotes may be adjusted with mutual written agreement of the parties. Failure to accept a quote in the stated time is deemed to mean the quote is rejected and the transaction will not take place. (I)

Monthly ERP: The Monthly ERP Energy Charge will be determined in accordance with a price quote accepted by the Customer plus a 5% adder, which will not be less than 0.15¢ per kWh, plus 0.294¢ per kWh for wheeling, plus losses. At customer request and based on the submitted Monthly ENF, the Company will provide a price quote for the next full calendar month for the ENF commodity energy only amount specified by the customer at the time of the request. The Company will respond to the request with a quote within 4 hours or as otherwise mutually agreed to. Customer will accept or reject the quote within 30 minutes. Customer communication regarding a price quote will be in the manner agreed to by the Company and the Customer. The quote may incorporate reasonable premiums to reflect the additional cost of ENF amounts that are in nonstandard block sizes (i.e., other than multiples of 25 MW) and such premium will not be separately stated. (I)

SCHEDULE 76R (Continued)

ENF AND ERP (Continued)
ERP Supply Options (Continued)
ERP Pricing (Continued)

The methods to communicate and the times to receive information and quotes may be adjusted with mutual written agreement of the parties. Failure to accept a quote in the stated time is deemed to mean the quote is rejected and the transaction will not take place.

On-peak hours (Heavy Load Hours, HLH) are between 6:00 a.m. and 10:00 p.m. PPT (hours ending 0700 through 2200), Monday through Saturday. Off-peak hours (Light Load Hours, LLH) are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all hours Sunday.

Losses will be included by multiplying the ERP Charge by the following adjustment factors:

Subtransmission Delivery Voltage	1.0337
Primary Delivery Voltage	1.0482
Secondary Delivery Voltage	1.0820

ACTUAL ENERGY USAGE

Actual Energy usage during times when ERP deliveries are occurring will be the amount of Energy above the Customer's Schedule 75 Baseline Energy.

IMBALANCE ENERGY SETTLEMENT

Imbalance Settlement Amounts are bill credits or charges resulting from hourly Imbalance Energy multiplied by the applicable hourly Settlement Price and summed for all hours in the billing period. Imbalance Energy is the kWh amount determined hourly as the deviation between Actual Energy for such hour and the ENF for such hour (i.e., Imbalance Energy = Actual Energy less ENF).

For any Imbalance Energy in any hour up to 7.5% of the hourly ENF (positive or negative amount), the Imbalance Settlement Amount for the hour is:

- For positive Imbalance Energy (where Customer receives more ERP than the ENF), the Imbalance Energy multiplied by the Settlement Price of the Dow Jones Mid-Columbia Hourly Price Index (DJ-Mid-C Hourly Index), plus 0.294¢ per kWh for wheeling, plus losses. **(I)**
- For negative Imbalance Energy (where Customer receives less ERP than the ENF), the Imbalance Energy is multiplied by the Settlement Price of the DJ-Mid-C Hourly Index plus 0.294¢ per kWh for wheeling, plus losses. **(I)**

SCHEDULE 76R (Continued)

IMBALANCE ENERGY SETTLEMENT (Continued)

For any Imbalance Energy in any hour in excess of 7.5% of the hourly ENF (positive or negative amount), the Imbalance Settlement Amount for the hour is:

- For positive excess Imbalance Energy, the excess Imbalance Energy multiplied by the Settlement Price, which is the Dow Jones Mid-Columbia Hourly Price Index (DJ-Mid-C Hourly Index), plus 10%, plus 0.294¢ per kWh for wheeling, plus losses. **(I)**
- For negative excess Imbalance Energy, the excess Energy Imbalance is multiplied by the Settlement Price of the DJ-Mid-C Hourly Index, less 10%, plus 0.294¢ per kWh for wheeling, **(I)** plus losses.

The Imbalance Settlement Amount may be a credit or charge in any hour.

DAILY ERP DEMAND

Daily ERP Demand is the highest 30 minute Demand occurring during the days that the Company supplies ERP to the Customer less the sum of the Customer's Schedule 75 Baseline Demand and any Unscheduled Demand. Daily ERP Demand will not be less than zero. Daily ERP Demand will be billed for each day in the month that the Company supplies ERP to the Customer.

If the sum of the Customer's Unscheduled and Schedule 75 Baseline Demand exceeds their Daily ERP Demand, no additional Daily Demand charges are applied to the service under this schedule for the applicable Billing Period.

UNSCHEDULED DEMAND

Unscheduled Demand is the difference in the highest 30 minute monthly Demand and the Customer's Baseline occurring when the Customer did not receive ERP.

ADJUSTMENTS

Service under this rider is subject to all adjustments as summarized in Schedule 100, except for: 1) any power cost adjustment recovery based on costs incurred while the Customer is taking Service under this schedule, and 2) Schedule 128.

SPECIAL CONDITIONS

1. Prior to receiving service under this schedule, the Customer and the Company must enter into a written agreement governing the terms and conditions of service.

2. Service under this schedule applies only to prescheduled ERP supplied by the Company pursuant to this schedule and the corresponding agreement. All other Energy supplied will be made under the terms of Schedule 75. All notice provisions of this schedule and agreement must be complied with for delivery of Energy. The Customer is required to maintain Schedule 75 service unless otherwise agreed to by the Company.

SCHEDULE 81
NONRESIDENTIAL
EMERGENCY DEFAULT SERVICE

AVAILABLE

In all territory served by the Company. The Company may restrict Customer loads returning to this schedule in accordance with Rule N Curtailment Plan and Rule C (Section 2).

APPLICABLE

To existing Nonresidential Customers who are no longer receiving Direct Access Service and have not provided the Company with the notice required to receive service under the applicable Standard Service rate schedule.

MONTHLY RATE

All charges for Emergency Default Service except the energy charge will be billed at the Customer's applicable Standard Service rate schedule for five business days after the Customer's initial purchase of Emergency Default Service.

ENERGY CHARGE DAILY RATE

The Energy Charge Daily Rate will be 125% of the Dow Jones Mid-Columbia Daily on- and off-peak Firm Electricity Price Index (DJ-Mid-C Firm Index) plus 0.294¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on-peak and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported. **(I)**

Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

Losses will be included by multiplying the Energy Charge Daily Rate by the following adjustment factors:

Subtransmission Delivery Voltage	1.0337
Primary Delivery Voltage	1.0482
Secondary Delivery Voltage	1.0820

REACTIVE DEMAND CHARGE

In addition to the charges as specified in the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

SCHEDULE 83
LARGE NONRESIDENTIAL
STANDARD SERVICE
(31 – 200 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customers whose Demand has not exceeded 200 kW more than six times in the preceding 13 months and has not exceeded 1,000 kW more than once in the preceding 13 months, or with seven months or less of service has not had a Demand exceeding 1,000 kW. Service under this Schedule is available for Secondary Delivery Voltage only.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge		
Single Phase Service	$30.00	(I)
Three Phase Service	$40.00	
Transmission and Related Services Charge		
per kW of monthly On-Peak Demand	$0.88	(C)
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 30 kW	$2.98	
Over 30 kW	$2.48	
per kW of monthly Demand	$2.05	(I)
Energy Charge ***		
Cost of Service Option per kWh On-Peak Period	6.178 ¢	(C)(R)
See below for Daily Pricing Option description Off-Peak Period	5.478 ¢	(N)
System Usage Charge		
per kWh	0.849 ¢	(I)

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the applicable POD.

*** Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday. (N)
(N)

SCHEDULE 83 (Continued)

MONTHLY RATE (Continued)

Energy Charge Options:

Any Energy Charge option selected by a Customer will remain in effect and continue to be the default option until the Customer has given the required notice to change the applicable Energy Charge Option. To change options, Customers must give notice as specified for that option below and must complete the specified term of their current option. The Cost of Service Option will be the default for Customers or new Customers who have not selected another option or Direct Access Service. If a Customer chooses Direct Access Service or a pricing option other than the Cost of Service Option, that Customer may not receive service under the Cost of Service Option until the next service year and with timely notice.

NON COST OF SERVICE OPTION

Daily Price Option - The Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Firm Index) plus 0.294¢ per kWh for wheeling, plus losses. If prices **(I)** are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported. To begin service under this option, the Customer receiving service under Cost of Service price option will notify the Company by the close of the November Election Window or for eligible Customers, the close of a Balance-of-Year Election Window.

Losses will be included by multiplying the above applicable Energy Charge Option by the following adjustment factors:

Secondary Delivery Voltage	1.0820

Non-Cost of Service Option is subject to Schedule 128, Short Term Transition Adjustment.

Interval metering and meter communications should be in place prior to initiation of service under this schedule. Where interval metering has not been installed, the Customer's Electricity usage will be billed as 65% on-peak and 35% off-peak. Upon installation of an interval meter, the Company will bill the Customer according to actual metered usage.

PLUG-IN ELECTRIC VEHICLE TIME OF USE (EV TOU) OPTION

Should a Customer receiving service under this Schedule 83 opt for a separately metered EV TOU option, the separately metered Electric Vehicle charging load will determine the applicable rate schedule under which EV TOU charging service is provided. For example, please refer to Schedules 32 and 38.

SCHEDULE 85
LARGE NONRESIDENTIAL
STANDARD SERVICE
(201 – 4,000 kW) (C)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Secondary Delivery Voltage Large Nonresidential Customer whose Demand has exceeded 200 kW more than six times in the preceding 13 months but has not exceeded 4,000 kW more than (C) once in the preceding 13 months, or with seven months or less of service has not had a Demand exceeding 4,000 kW. To each Primary Delivery Voltage Large Nonresidential Customer whose (C) Demand has not exceeded 4,000 kW more than once in the preceding 13 months, or with seven (C) months or less of service has not had a Demand exceeding 4,000 kW. (C)

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Point of Delivery (POD)*:

	Delivery Voltage		
	Secondary	Primary	
Basic Charge	$370.00	$390.00	(I)
Transmission and Related Services Charge			
per kW of monthly On-Peak Demand	$0.88	$0.85	
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 200 kW	$3.12	$3.04	
Over 200 kW	$2.12	$2.04	(R)
per kW of monthly On-Peak Demand	$2.05	$1.99	(I)
Energy Charge			
On-Peak Period***	6.085 ¢	5.928 ¢	(R)
Off-Peak Period***	5.085 ¢	4.928 ¢	
See below for Daily Pricing Option description.			
System Usage Charge			
per kWh	0.194 ¢	0.187 ¢	(R)

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the applicable POD.

*** Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

SCHEDULE 85 (Continued)

MONTHLY RATE (Continued)

Energy Charge Options:

Any Energy Charge option selected by a Customer will remain in effect and continue to be the default option until the Customer has given the required notice to change the applicable Energy Charge Option. To change options, Customers must give notice as specified for that option below and must complete the specified term of their current option. The Cost of Service Option will be the default for Customers or new Customers who have not selected another option or Direct Access Service. If a Customer chooses Direct Access Service or a pricing option other than the Cost of Service Option, that Customer may not receive service under the Cost of Service Option until the next service year and with timely notice.

PLUG-IN ELECTRIC VEHICLE TIME OF USE (EV TOU) OPTION

Should a Customer receiving service under this Schedule 85 opt for a separately metered EV TOU option, the separately metered Electric Vehicle charging load will determine the applicable rate Schedule under which EV TOU charging service is provided. For example, please refer to Schedules 32 and 38.

NON COST OF SERVICE OPTION

Daily Price Option - The Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Firm Index) plus 0.294¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported. To begin service under this option, the Customer receiving service under Cost of Service price option will notify the Company by the close of the November Election Window or for eligible Customers, the close of a Balance-of-Year Election Window. **(I)**

Losses will be included by multiplying the above applicable Energy Charge Option by the following adjustment factors:

Primary Delivery Voltage	1.0482
Secondary Delivery Voltage	1.0820

Non-Cost of Service Option is subject to Schedule 128, Short Term Transition Adjustment.

Interval metering and meter communications should be in place prior to initiation of service under this schedule. Where interval metering has not been installed, the Customer's Electricity usage will be billed as 65% on-peak and 35% off-peak. Upon installation of an interval meter, the Company will bill the Customer according to actual metered usage.

SCHEDULE 89
LARGE NONRESIDENTIAL
STANDARD SERVICE
(>4,000kW) (C)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has exceeded 4,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 4,000 kW. (C) (C)

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Point of Delivery (POD)*:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge	$4,850.00	$4,460.00	$5,130.00	(I)
Transmission and Related Services Charge				
per kW of monthly On-Peak Demand	$0.88	$0.85	$0.84	
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.90	$1.85	$1.85	
Over 4,000 kW	$1.26	$1.21	$1.21	
per kW of monthly On-Peak Demand	$2.05	$1.99	$1.12	(I)
Energy Charge				
On-Peak Period***	5.781 ¢	5.611 ¢	5.537 ¢	(R)
Off-Peak Period***	4.781 ¢	4.611 ¢	4.537 ¢	
See below for Daily Pricing Option description.				
System Usage Charge				
Per kWh	0.162 ¢	0.157 ¢	0.154 ¢	(R)

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the applicable POD.

*** Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

SCHEDULE 89 (Continued)

MONTHLY RATE (Continued)
Energy Charge Options:

Any Energy Charge option selected by a Customer will remain in effect and continue to be the default option until the Customer has given the required notice to change the applicable Energy Charge Option. To change options, Customers must give notice as specified for that option below and must complete the specified term of their current option. The Cost of Service Option will be the default for Customers or new Customers who have not selected another option or Direct Access Service. If a Customer chooses Direct Access Service or a pricing option other than the Cost of Service Option, it may not receive service under the Cost of Service Option until the next service year and with timely notice.

NON-COST OF SERVICE OPTION

Daily Price Option - The Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Firm Index) plus 0.294¢ per kWh for wheeling, plus losses. If prices **(I)** are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported. To begin service under this option, the Customer receiving service under Cost of Service price option will notify the Company by the close of the November Election Window or for eligible Customers, the close of a Balance-of-Year Election Window.

Losses will be included by multiplying the above applicable Energy Charge Option by the following adjustment factors:

Subtransmission Delivery Voltage	1.0337
Primary Delivery Voltage	1.0482
Secondary Delivery Voltage	1.0820

Non-Cost of Service Option is subject to Schedule 128, Short Term Transition Adjustment

PLUG-IN ELECTRIC VEHICLE TIME OF USE (EV TOU) OPTION

Should a Customer receiving service under this Schedule 89 opt for a separately metered EV TOU option, the separately metered Electric Vehicle charging load will determine the applicable rate schedule under which EV TOU charging service is provided. For example, please refer to Schedules 32 and 38.

SCHEDULE 91 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)
Option A - Luminaire (Continued)

The Customer is responsible for repair or replacement of luminaires and circuits damaged as a result of rotted wood poles owned by the Customer. **(N)** **(N)**

The Company may remove or discontinue service to any luminaire and related equipment that has become unsafe or unsatisfactory for further service by reason of deterioration, storm, flood, and lightning, proximity to interference by trees or structures, or other causes as determined by the Company. The Company will notify the Customer as soon as reasonably practical of any such service discontinuation and luminaire replacement schedule.

Option B - Luminaire

Option B provides electricity service to Customer purchased and owned luminaires at the monthly Option B rate applicable to the installed type of light.

The Company does not at any time assume ownership of Option B luminaires.

As defined herein, the Company provides for maintenance only to luminaires and related equipment at the applicable monthly Option B rate. The Company will replace non-repairable Option B luminaires for which the Customer is charged and billed the appropriate replacement costs [1], in addition to the applicable monthly Option B rate.

Maintenance Service under Option B

Includes preventative group lamp replacement and glassware cleaning subject to the Company's operating schedule.

Maintenance under Option B luminaires specifically does not include replacement of failed or failing ballasts or replacement of luminaires that are deemed inoperable due to general deterioration, lack of replacement parts, or replacement of parts associated with Emergency Repair that will not bring the unit into operable status. Such inoperable luminaires will be designated as non-repairable luminaires. This exclusion does not include replacements of Power Doors where the Customer is qualified and paying the applicable Cobrahead Power Door rate. In addition, maintenance under Option B luminaires excludes maintenance related to vegetation management, luminaire relocation or modification of the luminaire (such as adding light shields).

(1) Replacement costs include: Installation Labor + Material costs and loading + Removal Labor = total billable charges. For applicable labor rates, refer to page 91-8 of this Schedule.

SCHEDULE 91 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)

Option C – Luminaire

Option C provides electricity service to luminaires that are purchased, owned and maintained by the Customer and installed on Customer-owned poles. As a condition to the election of Option C, Customer is responsible for ensuring that all new underground service installations of Option C luminaires are isolated by a disconnect switch or fuse. Both the equipment used to isolate the luminaire and its location must be approved by the Company. **(C)**

Maintenance Service under Option C

The Company does not maintain Customer-purchased lighting when mounted on Customer-owned poles. Such maintenance and service is the sole responsibility of the Customer.

Special Provisions for Option B to Option C Luminaire Conversion and Future Maintenance Election

1. The Company will, with not less than 180 days written notice from the Customer (the requesting municipality) and subject to completion of all conditions necessary to finalize such election, convert the entirety of the Customer's lighting service under Option B luminaire lighting rates to the equivalent Option C luminaires lighting rates (with respect to Monthly kWh usage) including Option B luminaires attachment to Company-owned poles.

2. Upon such conversion, the Customer will assume all on-going maintenance responsibilities for the luminaires and associated circuits in accordance with this schedule's provisions for Option C luminaires. The Customer may not require that the Company provide new Option B lighting following the conversion to Option C luminaires. The Customer must notify and inform all affected residents of the conversion that all maintenance and repair services are the sole responsibility of the Customer, and not the Company.

3. The Customer may choose the Schedule 91 Option B to Schedule 95 Option C Luminaire Conversion and Future Maintenance Election as described in Schedule 95 if converting to Schedule 95 Option C luminaires and the above notice has not been given.

SCHEDULE 91 (Continued)

MONTHLY RATE

In addition to the service rates for Option A and B lights, all Customers will pay the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Transmission and Related Services Charge	0.182 ¢ per kWh	**(R)**
Distribution Charge	4.682 ¢ per kWh	**(I)**
Energy Charge		
Cost of Service Option	5.078 ¢ per kWh	**(R)**

Daily Price Option – Available only to Customers with an average load of five MW or greater on Schedules 91 and 95 and those customers that met the five MW or greater threshold prior to converting to lights from Schedule 91 to Schedule 95. This selection of this option applies to all luminaires served under Schedules 91 and 95. This option gives eligible Customers an option between a daily Energy price and a Cost of Service option for the Energy charge. In addition to the daily Energy price, the Customer will pay a Basic Charge of $75 per month to help offset the costs of billing this option. The daily Energy price for all kWh will be the Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Firm Index) plus 0.294¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. **(I)**

Prices reported with no transaction volume or as "survey-based" will be considered reported. For the purposes of calculating the daily on- and off-peak usage, actual kWhs will be determined for each month, using Sunrise Sunset Tables with adjustments for typical photocell operation and 4,100 annual burning hours.

For Customers billed on the Daily price Option, an average of the daily rates will be used to bill installations and removals that occur during the month. Any additional analysis of billing options and price comparisons beyond the monthly bill will be billed at a rate of $100 per manhour.

Losses will be included by multiplying the applicable daily Energy price by 1.0820.

The Daily Price Option is subject to Schedule 128, Short Term Transition Adjustment.

Enrollment for Service

To begin service under the Daily Price Option on January 1st, the Customer will notify the Company by 5:00 p.m. PPT on November 15th (or the following working day if the 15th falls on a weekend or holiday) of the year prior to the service year of its choice of this option. Customers selecting this option must commit to this option for an entire service year. The Customer will continue to be billed on this option until timely notice is received to return to the Cost of Service Option.

SCHEDULE 91 (Continued)

RATES FOR STANDARD LIGHTING

High-Pressure Sodium (HPS) Only – Service Rates

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
Cobrahead Power Doors **	70	6,300	30	*	$ 1.28	(R)
	100	9,500	43	*	1.29	
	150	16,000	62	*	1.30	
	200	22,000	79	*	1.36	
	250	29,000	102	*	1.37	
	400	50,000	163	*	1.39	
Cobrahead	70	6,300	30	$ 5.20	1.53	
	100	9,500	43	5.14	1.52	
	150	16,000	62	5.17	1.53	
	200	22,000	79	5.80	1.58	(I)(R)
	250	29,000	102	5.94	1.61	
	400	50,000	163	6.32	1.64	
Flood	250	29,000	102	6.73	1.70	
	400	50,000	163	6.72	1.69	
Early American Post-Top	100	9,500	43	5.92	1.60	
Shoebox (bronze color, flat lens, or drop lens, multi-volt)	70	6,300	30	6.65	1.70	
	100	9,500	43	6.83	1.72	
	150	16,000	62	7.14	1.77	(I)(R)

* Not offered.
** Service is only available to Customers with total power door luminaires in excess of 2,500.

RATES FOR STANDARD POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Fiberglass, Black	20	$ 6.51	$ 0.19	(I)
Fiberglass, Bronze	30	10.26	0.29	
Fiberglass, Gray	30	11.07	0.32	
Wood, Standard	30 to 35	7.40	0.21	
Wood, Standard	40 to 55	9.70	0.28	(I)

SCHEDULE 91 (Continued)

RATES FOR CUSTOM LIGHTING

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	
Special Acorn-Types						
HPS	100	9,500	43	$ 10.27	$ 2.08	(I)(R)
HADCO Victorian, HPS	150	16,000	62	10.29	2.10	
	200	22,000	79	11.06	2.22	
	250	29,000	102	11.07	2.22	
HADCO Capitol Acorn, HPS	100	9,500	43	14.39	2.56	
	150	16,000	62	14.44	2.61	
	200	22,000	79	14.31	2.60	
	250	29,000	102	14.33	2.61	
Special Architectural Types						
HADCO Independence, HPS	100	9,500	43	10.40	2.08	
	150	16,000	62	10.07	2.05	
HADCO Techtra, HPS	100	9,500	43	19.52	3.14	
	150	16,000	62	19.19	3.12	(I) (R)
	250	29,000	102	18.53	3.08	(I)
HADCO Westbrooke, HPS	70	6,300	30	13.34	2.43	
	100	9,500	43	13.09	2.40	
	150	16,000	62	13.10	2.41	
	200	22,000	79	13.39	2.48	
	250	29,000	102	13.27	2.47	(I)(R)

SCHEDULE 91 (Continued)

RATES FOR CUSTOM LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
Special Types						
Cobrahead, Metal Halide	150	10,000	60	$ 5.80	$ 1.84	(R)
Flood, Metal Halide	350	30,000	139	8.16	2.15	
Flood, HPS	750	105,000	285	10.25	2.69	(I)
Holophane Mongoose, HPS	150	16,000	62	10.77	2.15	
	250	29,000	102	10.07	2.09	(I)(R) (D)
Option C Only **						
Ornamental Acorn Twin	85	9,600	64	*	*	
Ornamental Acorn	55	2,800	21	*	*	
Ornamental Acorn Twin	55	5,600	42	*	*	
Composite, Twin	140	6,815	54	*	*	
	175	9,815	66	*	*	

* Not offered.
** Rates are based on current kWh energy charges.

RATES FOR CUSTOM POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Aluminum, Regular	16	$ 8.86	$ 0.25	(I)
	25	14.70	0.42	
	30	15.89	0.45	
	35	19.02	0.54	
Aluminum Davit	25	14.67	0.42	
	30	14.60	0.42	
	35	15.97	0.46	
	40	21.68	0.62	
Aluminum Double Davit	30	21.58	0.62	(I)

SCHEDULE 91 (Continued)

RATES FOR CUSTOM POLES (Continued)

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Aluminum, HADCO, Fluted Victorian Ornamental	14	$12.99	$ 0.37	(I)
Aluminum, HADCO, Non-Fluted Techtra Ornamental	18	25.57	0.73	
Aluminum, HADCO, Fluted Ornamental	16	13.28	0.38	
Aluminum, HADCO, Non-Fluted Ornamental	16	27.18	0.78	
Aluminum, HADCO, Fluted Westbrooke	18	25.64	0.73	
Aluminum, HADCO, Non-Fluted Westbrooke	18	27.18	0.78	
Aluminum, Painted Ornamental	35	43.67	1.25	
Concrete. Decorative Ameron	20	25.51	0.73	(R)
Concrete, Ameron Post-Top	25	25.51	0.73	(R)
Fiberglass, HADCO, Fluted Ornamental Black	14	15.70	0.45	
Fiberglass, Smooth	18	6.48	0.19	
Fiberglass, Regular				
color may vary	22	5.80	0.17	
	35	9.53	0.27	
Fiberglass, Anchor Base, Gray	35	17.45	0.50	
Fiberglass, Direct Bury with Shroud	18	10.50	0.30	(I)

(D)

SERVICE RATE FOR OBSOLETE LIGHTING

The following equipment is not available for new installations under Options A and B. To the extent feasible, maintenance will be provided. Obsolete Lighting will be replaced with the Customer's choice of Standard or Custom equipment. The Customer will then be billed at the appropriate Standard or Custom rate. If an existing Mercury Vapor luminaire requires the replacement of a ballast, the unit will be replaced with a corresponding HPS unit.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	
Cobrahead, Mercury Vapor	100	4,000	39	*	*	
	175	7,000	66	$ 5.08	$ 1.46	(R)
	250	10,000	94	*	*	
	400	21,000	147	5.82	1.60	(I)
	1,000	55,000	374	6.60	1.92	(I)
Special Box Similar to GE "Space-Glo"						
HPS	70	6,300	30	6.73	1.62	
Mercury Vapor	175	7,000	66	6.68	1.57	(R)

* Not offered.

SCHEDULE 91 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
Special Box, Anodized Aluminum Similar to GardCo Hub						
HPS - Twin	70	6,300	60	*	*	
HPS	70	6,300	30	*	*	
	100	9,500	43	*	$ 1.97	(R)
	150	16,000	62	*	1.99	
	250	29,000	102	*	*	
	400	50,000	163	*	*	
Metal Halide	250	20,500	99	*	1.20	
	400	40,000	156	*	1.20	
Cobrahead, Metal Halide	175	12,000	71	$ 6.08	1.69	
Flood, Metal Halide	400	40,000	156	6.94	1.74	(I)
Cobrahead, Dual Wattage, HPS						
70/100 Watt Ballast	100	9,500	43	*	1.53	
100/150 Watt Ballast	100	9,500	43	*	1.53	
100/150 Watt Ballast	150	16,000	62	*	1.55	(R)
Special Architectural Types Including Philips QL Induction Lamp Systems						
HADCO Victorian, QL	85	6,000	32	*	0.67	(R)(M)
	165	12,000	60	*	0.94	
HADCO Techtra, QL	165	12,000	60	23.22	1.14	(I)(R)(M)
Special Architectural Types						
KIM SBC Shoebox, HPS	150	16,000	62	*	2.55	(R)
KIM Archetype, HPS	250	29,000	102	*	2.81	
	400	50,000	163	*	2.20	
Special Acorn-Type, HPS	70	6,300	30	10.25	2.06	(I)(R)
Special GardCo Bronze Alloy						
HPS	70	5,000	30	*	*	
Mercury Vapor	175	7,000	66	*	*	
Special Acrylic Sphere						
Mercury Vapor	400	21,000	147	*	*	(M)

* Not offered.

SCHEDULE 91 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
Early American Post-Top, HPS						
Black	70	6,300	30	$5.81	$1.49	(I)(R)(M)
Rectangle Type	200	22,000	79	*	*	
Incandescent	92	1,000	31	*	*	
	182	2,500	62	*	*	
Town and Country Post-Top						
Mercury Vapor	175	7,000	66	5.82	1.50	(I)(R)(M)
Flood, HPS	70	6,300	30	5.20	1.58	
	100	9,500	43	5.17	1.52	
	200	22,000	79	6.69	1.66	(I)
Cobrahead, HPS						
Power Door	310	37,000	124	6.33	2.00	(R)
Special Types Customer-Owned & Maintained						
Ornamental, HPS	100	9,500	43	*	*	
Twin Ornamental, HPS	Twin 100	9,500	86	*	*	
Compact Fluorescent	28	N/A	12	*	*	

* Not offered.

(M)

SCHEDULE 91 (Continued)

RATES FOR OBSOLETE LIGHTING POLES (T)

Type of Pole	Poles Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Aluminum Post	30	$ 8.86	*	(I) (M)
Bronze Alloy GardCo	12	*	$ 0.23	(R)
Concrete, Ornamental	35 or less	14.70	0.42	(I)
Steel, Painted Regular **	25	14.70	0.42	
Steel, Painted Regular **	30	15.89	0.45	
Steel, Unpainted 6-foot Mast Arm **	30	*	0.42	
Steel, Unpainted 6-foot Davit Arm **	30	*	0.42	
Steel, Unpainted 8-foot Mast Arm **	35	*	0.46	
Steel, Unpainted 8-foot Davit Arm **	35	*	0.46	
Wood, Laminated without Mast Arm	20	6.51	0.19	
Wood, Laminated Street Light Only	20	6.51	*	(M)
Wood, Curved Laminated	30	10.26	0.29	
Wood, Painted Underground	35	7.40	0.21	
Wood, Painted Street Light Only	35	7.40	*	(I)

* Not offered.
** Maintenance does not include replacement of rusted steel poles. (D)(M)

SPECIALTY SERVICES OFFERED

Upon Customer request and subject to the Company's agreement, the Company will provide the following streetlighting services based on the Company's total costs including Company indirect charges:

- Trimming of trees adjacent to streetlight equipment and circuits.
- Arterial patrols to ensure correct operation of streetlights.
- Painting or staining of wood and steel streetlight poles.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 91 (Continued)

SPECIAL CONDITIONS

1. The Company may offer temporary or experimental lighting equipment that is not otherwise listed in this rate schedule. Temporary or experimental lighting will be offered at a billing rate based on approved prices for near equivalent lighting service equipment. The use of temporary or experimental lighting will be for a limited duration not to exceed one-year at which time the lighting service equipment will either be removed at Customer expense or the Company will file with the Commission to add the luminaire type to this rate schedule.

2. Customer is responsible for the cost associated with trenching, boring, conduit and restoration required for underground service to streetlighting.

3. Unless otherwise specifically provided, the location of Company-owned streetlighting equipment and poles may be changed at the Customer's request and upon payment by the Customer of the costs of removal and reinstallation.

4. If Company-owned streetlighting equipment or poles are removed at the Customer's request, a charge will be made consisting of the estimated original cost, less depreciation, less salvage value, plus removal cost. This provision does not pertain to the sale of Company-owned equipment. This condition applies if a Customer's selection of service under this Schedule requires the removal of Company-owned streetlighting equipment or poles.

5. If circuits or poles not already covered under Special Condition 2 or 3 are removed or relocated at the Customer's request, the Customer is responsible for all associated costs for labor and materials incurred when fulfilling this request.

6. For Option C lights: The Company does not provide the circuit on new Option C **(C)**
installations. **(C)**

7. For Option C lights in service prior to January 31, 2006: When the Company furnishes Electricity to luminaires owned and maintained by the Customer and installed on Customer-owned poles that are not included in the list of equipment in this schedule, usage for the luminaire will be estimated by the Company. When the Customer and the Company cannot agree, the Commission will determine the estimated usage.

8. For Option A and Option B lights: The Company shall not be liable when either (i) the luminaires become inoperable or (ii) repair or replacement of inoperable luminaires is delayed or prevented; provided that, such inoperability of the luminaires or delay or prevention of repair or replacement is due to any cause beyond the Company's control, or that otherwise could not reasonably be foreseen or guarded against including but not limited to such causes as: strikes, lockouts, labor troubles, riots, insurrection, war, acts of God, extreme weather conditions, access to equipment, or the like.

SCHEDULE 92
TRAFFIC SIGNALS
(NO NEW SERVICE)
STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments where funds for payment of Electricity are provided through taxation or property assessment for traffic signals and warning facilities in systems containing at least 50 intersections on public streets and highways. This schedule is available only to those governmental agencies receiving service under Schedule 92 as of September 30, 2001.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Transmission and Related Services Charge	0.171	¢ per kWh	(R)
Distribution Charge	2.215	¢ per kWh	(I)
Energy Charge	5.204	¢ per kWh	(R)

* See Schedule 100 for applicable adjustments.

ELECTION WINDOW

Balance-of-Year Election Window

The Balance-of-Year Election Window begins at 8:00 a.m. on February 15th. The Window will remain open from 8:00 a.m. of the first day through 5:00 p.m. of the third business day of the Election Window.

Balance-of-Year Election Window, a Customer may notify the Company of its choice to move to Direct Access Service. For the February 15th election, the move is effective on the following April 1st. A Customer may not choose to move from an alternative option back to Cost of service during a Balance-of-Year Election Window.

SCHEDULE 95
STREET AND HIGHWAY LIGHTING
NEW TECHNOLOGY
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments for lighting service utilizing Company approved new technology streetlighting equipment for public streets and highways and public grounds where funds for payment of Electricity generally are provided through taxation or property assessment.

CHARACTER OF SERVICE

From dusk to dawn daily, controlled by a photoelectric control to be mutually agreeable to the Customer and Company for an average of 4,100 hours annually.

LUMINAIRE SERVICE OPTIONS - The Company offers the following Luminaire Service Options at the applicable rates specified herein.

The Customer will elect the Luminaire Service Option at the time of initial luminaire installation.

Option A - Luminaire

Option A provides electricity service to luminaires that are purchased, owned, and maintained by the Company with attachment to Company-owned poles at the monthly Option A rate applicable to the installed type of light.

Maintenance Service under Option A

The Company will only perform emergency maintenance on the luminaires listed in this schedule. The Company does not perform preventative maintenance on the luminaires listed in this schedule.

The Company will repair or replace inoperable luminaires as soon as reasonably possible, subject to the Company's operating schedule, following notification to PGE's Customer Service or PGE's Outdoor Lighting Services[1] department by the Customer, a member of the public, or a PGE employee performing luminaire replacement work. PGE has no obligation for repair or replacement of inoperable luminaires other than as described in this section of the tariff. (C)

(1) Contact PGE's Outdoor Lighting Services at 503-736-5710, PGE's Customer Service 503-228-6322 or 1-800-542-8818, or www.portlandgeneral.com to report an inoperable streetlight.

SCHEDULE 95 (Continued)

STREETLIGHT POLES SERVICE OPTIONS

See Schedule 91 for Streetlight poles service options.

MONTHLY RATE

In addition to the service rates for Option A lights, all Customers will pay the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Transmission and Related Services Charge	0.182 ¢ per kWh	(R)
Distribution Charge	4.682 ¢ per kWh	(I)
Energy Charge		
Cost of Service Option	5.078 ¢ per kWh	(R)

NON-COST OF SERVICE OPTION

Daily Price Option – Available only to Customers with an average load of five MW or greater on Schedules 91 and 95 and those customers that met the five MW or greater threshold prior to converting to lights from Schedule 91 to Schedule 95. This selection of this option applies to all luminaires served under Schedules 91 and 95. This option gives eligible Customers an option between a daily Energy price and a Cost of Service option for the Energy charge. In addition to the daily Energy price, the Customer will pay a Basic Charge of $75 per month to help offset the costs of billing this option. The daily Energy price for all kWh will be the Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Firm Index) plus 0.294¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. (I)

Prices reported with no transaction volume or as "survey-based" will be considered reported. For the purposes of calculating the daily on- and off-peak usage, actual kWhs will be determined for each month, using Sunrise Sunset Tables with adjustments for typical photocell operation and 4,100 annual burning hours.

For Customers billed on the Daily Price Option, an average of the daily rates will be used to bill installations and removals that occur during the month. Any additional analysis of billing options and price comparisons beyond the monthly bill will be billed at a rate of $100 per manhour.

Losses will be included by multiplying the applicable daily Energy price by 1.0820.

The Daily Price Option is subject to Schedule 128, Short Term Transition Adjustment.

SCHEDULE 95 (Continued)

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rate [(1)]	Straight Time	Overtime
	$120.00 per hour	$167.00 per hour

[(1)] Per Article 20.2 of the Collective Bargaining Agreement Union No. 125 Contract, overtime is paid at the Overtime Rate for a minimum of one hour.

RATES FOR STANDARD LIGHTING

Light-Emitting Diode (LED) Only – Option A Service Rates

LED lighting is new to the Company and pricing is changing rapidly. The Company may adjust rates under this schedule based on actual frequency of maintenance occurrences and changes in material prices.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rate Option A	
LED	37	2,530	13	$3.46	(R)
LED	50	3,162	17	3.46	
LED	52	3,757	18	3.88	
LED	67	5,050	23	4.36	
LED	106	7,444	36	5.22	(R)

SCHEDULE 95 (Continued)

SPECIAL CONDITIONS

1. Customer is responsible for the cost associated with trenching, boring, conduit and restoration required for underground service to streetlighting.

2. Unless otherwise specifically provided, the location of Company-owned streetlighting equipment and poles may be changed at the Customer's request and upon payment by the Customer of the costs of removal and reinstallation.

3. If Company-owned streetlighting equipment or poles are removed at the Customer's request, a charge will be made consisting of the estimated original cost, less depreciation, less salvage value, plus removal cost. This provision does not pertain to the sale of Company-owned equipment. This condition applies if a Customer's selection of service under this Schedule requires the removal of Company-owned streetlighting equipment or poles.

4. If circuits or poles not already covered under Special Conditions 2 or 3 are removed or relocated at the Customer's request, the Customer is responsible for all associated costs for labor and materials incurred when fulfilling this request.

5. For Option C lights: The Company does not provide the circuit on new installations. **(C)**

6. For Option A lights: The Company shall not be liable when either (i) the luminaires become inoperable or (ii) repair or replacement of inoperable luminaires is delayed or prevented; provided that, such inoperability of the luminaires or delay or prevention of repair or replacement is due to any cause beyond the Company's control, or that otherwise could not reasonably be foreseen or guarded against including but not limited to such causes as: strikes, lockouts, labor troubles, riots, insurrection, war, acts of God, extreme weather conditions, access to equipment, or the like.

7. For Option C lights: The Customer must ensure that (i) all maintenance and other work associated with this schedule is in compliance with the applicable requirements of OSHA, OPUC Safety Rules, the NESC and/or NEC and (ii) that all such work is performed by a Qualified Worker. A "Qualified Worker" means one who is knowledgeable about the construction and operation of the electric power generation, transmission, and distribution equipment as it relates to his or her work, along with the associated hazards, as demonstrated by satisfying the qualifying requirements for a "qualified person" or "qualified employee" with regard to the work in question as described in 29 CFR 1910.269 effective January 31, 1994, as it may be amended from time to time. In this case, a Qualified Worker is a journeyman lineman, or someone who has the equivalent training, expertise and experience to perform journeyman lineman work.

SCHEDULE 123
DECOUPLING ADJUSTMENT

PURPOSE

This Schedule establishes balancing accounts and rate adjustment mechanisms to track and mitigate a portion of the transmission, distribution and fixed generation revenue variations caused by variations in applicable Customer Energy usage.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all Residential and Nonresidential Customers located within the Company's service territory except those Nonresidential Customers whose load exceeded one aMW at a Point of Delivery during the prior calendar year or those Nonresidential Customers qualifying as a Self-Directing Customer. Customers so exempted will not be charged the prices contained in this schedule.

DEFINITIONS

For the purposes of this tariff, the following definition will apply:

> **Energy Efficiency Measures (EEMs)** – Actions that enable customers to reduce energy use. EEMs can be behavioral or equipment-related.
>
> **Self-Directing Customer (SDC)** - Pursuant to OAR 860-038-0480, to qualify to be a SDC, the Large Nonresidential Customer must have a load that exceeds one aMW at a Site as defined in Rule B and receive certification from the Oregon Department of Energy as an SDC.

SALES NORMALIZATION ADJUSTMENT (SNA)

The SNA reconciles on a monthly basis, for Customers served under Schedules 7, 32 and 532, differences between a) the monthly revenues resulting from applying distribution, transmission and fixed generation charges (Fixed Charge Energy Rate) of 6.630 cents/kWh for Schedule 7 **(I)** and 6.407 cents/kWh for Schedules 32 and 532 to weather-normalized kWh Energy sales, and **(I)** b) the Fixed Charge Revenues that would be collected by applying the Monthly Fixed Charge per Customer of $56.77 per month for Schedule 7 and $95.05 per month for Schedules 32 and **(I)** 532 to the numbers of active Schedule 7 and Schedule 32 and 532 Customers, respectively, for each month.

The SNA will calculate monthly as the Fixed Charge Revenue less actual weather-adjusted revenues and will accrue to the SNA Balancing Account. The monthly amount accrued may be positive (an under-collection) or negative (an over-collection). The SNA is divided into sub-accounts so that net accruals for Schedule 7 will track separately from the net accruals for Schedules 32 and 532.

SCHEDULE 123 (Continued)

NONRESIDENTIAL LOST REVENUE RECOVERY ADJUSTMENT (LRRA)

The Nonresidential Lost Revenue Recovery Adjustment is applicable to all customers except those served under Schedules 7, 32 and 532 or as otherwise exempted above. Nonresidential Lost Revenue Recovery amounts will be equal to the reduction in distribution, transmission, and fixed generation revenues due to the reduction in kWh sales as reported to the Company by the Energy Trust of Oregon, resulting from EEMs implemented during prior calendar years attributable to EEM funding incremental to Schedule 108, adjusted for EEM program kWh savings incorporated into the test year load forecast used to determine base rates. Also included are differences in actual energy savings from a test year forecast associated with the conversion to LED streetlighting+ in Schedule 95 reported by the Company. When base rates are adjusted in the future as a result of a general rate review, the test year load forecast used to determine new base rates will reflect all energy efficiency kWh savings that have been previously achieved. The cumulative kWh savings are eligible for Lost Revenue Recovery until new base rates are established as a result of a general rate review; the kWh base is then reset to equal the amount of kWh savings that accrue from EEMs following an adjustment in base rates. **(C)**

The Lost Revenue Recovery Adjustment may be positive or negative. A negative Lost Revenue Recovery Adjustment for a given test year will occur if kWh savings reported by the Energy Trust of Oregon, plus the energy savings associated with the conversion to LED streetlighting in Schedule 95, are less than those estimated in setting base rates. A positive Lost Revenue Recovery Adjustment for a given test year will occur if kWh savings reported by the Energy Trust of Oregon, plus the energy savings associated with the conversion to LED streetlighting in Schedule 95, are greater than those estimated for the test year in setting base rates. The LRRA for each year subsequent to the test year will incorporate incremental kWh savings reported by the Energy Trust of Oregon for that year.

For the purposes of this Schedule, the Lost Revenue Recovery Adjustment is the product of: (1) the reduction in kWh sales resulting from ETO-reported EEMs plus the energy savings associated with the conversion to LED streetlighting in Schedule 95, and (2) the weighted average of applicable retail base rates (the Lost Revenue Rate). Applicable base rates for Nonresidential Customers are defined as the schedule-weighted average of transmission, distribution, and fixed generation charges; including those contained in Schedule122 and other applicable schedules. System usage or distribution charges will be adjusted to include only the recovery of Trojan Decommissioning expenses and the Customer Impact Offset. Franchise fee recovery is not included in the Lost Revenue Rate. The applicable Lost Revenue Rate is 4.464 cents per kWh. **(I)**

SNA and LRRA BALANCING ACCOUNTS

The Company will maintain a separate balancing account for the SNA, applicable to Schedules 7, 32 and 532, and for the Nonresidential LRRA for the remaining applicable nonresidential Schedules. Each balancing account will record over- and under-collections resulting from differences as determined, respectively, by the SNA and LRRA mechanisms. The accounts will accrue interest at the Commission-authorized Modified Blended Treasury Rate established for deferred accounts.

SCHEDULE 123 (Continued)

DECOUPLING ADJUSTMENT (Continued)

Schedule	Adjustment Rate
589	
Secondary	(0.011) ¢ per kWh
Primary	(0.011) ¢ per kWh
Subtransmission	(0.011) ¢ per kWh
591	(0.011) ¢ per kWh
592	(0.011) ¢ per kWh
595	(0.011) ¢ per kWh

TIME AND MANNER OF FILING

Commencing in 2014, the Company will submit to the Commission the following information by November 1 of each year: (C)

1. The proposed price changes to this Schedule to be effective on January 1st of the subsequent year based on a) the amounts in the SNA Balancing Accounts and b) the amount in the LRRA Balancing Account. (C)

2. Revisions to this Schedule which reflect the new proposed prices and supporting work papers detailing the calculation of the new proposed prices and the SNA weather-normalizing adjustments.

(D)

SCHEDULE 123 (Concluded)

SPECIAL CONDITIONS

1. The Fixed Charge Energy Rate, Monthly Fixed Charge per Customer and the Lost Revenue Rate will be updated concurrently with a change in the applicable base revenues used to determine the rates.

2. Weather-normalized energy usage by applicable rate schedule will be determined in a manner equivalent to that used for determining the forecasted loads used to establish base rates.

3. No revision to any SNA or LRRA Adjustment Rate will result in an estimated average annual rate increase greater than 2% to the applicable SNA or LRRA rate schedule, based on the net rates in effect on the effective date of the Schedule 123 rate revisions. Rate revisions resulting in a rate decrease are not subject to the 2% limit.

(D)

SCHEDULE 125
ANNUAL POWER COST UPDATE

PURPOSE

The purpose of this adjustment schedule is to define procedures for annual rate revisions due to changes in the Company's projected Net Variable Power Costs (the Annual Power Cost Update). This schedule is an "automatic adjustment clause" as defined in ORS 757.210(1), and is subject to review by the Commission at least once every two years.

APPLICABLE

To all Cost-of-Service bills for Electricity Service served under the following rate schedules 7, 15, 32, 38, 47, 49, 75, 83, 85, 89, 91, 92, and 95. Customers served under the daily price option contained in schedules 32, 38, 75, 81, 83, 85, 89, 91 and 95 are exempt from Schedule 125. (C)

NET VARIABLE POWER COSTS

Net Variable Power Costs (NVPC) are the power costs for energy generated and purchased. NVPC are the net cost of fuel and emission control chemicals, fuel and emission control chemical transportation, power contracts, transmission/wheeling, wholesale sales, hedges, options and other financial instruments incurred to serve retail load. (C) (C)

RATES

This adjustment rate is subject to increases or decreases, which may be made without prior hearing, to reflect increases or decreases, or both, in NVPC.

ANNUAL UPDATES

The following updates will be made in each of the Annual Power Cost Update filings:

- Forced Outage Rates based on a four-year rolling average.
- Projected planned plant outages.
- Wind energy forecast based on a five-year rolling average. (N)
- Costs associated with wind integration. (N)
- Forward market prices for both gas and electricity.
- Projected loads.
- Contracts for the purchase or sale of power and fuel.
- Emission control chemical costs. (N)
- Thermal plant variable operation and maintenance, including the cost of transmission losses, for dispatch purposes. (C) (C)
- Changes in hedges, options, and other financial instruments used to serve retail load.
- Transportation contracts and other fixed transportation costs.
- No other changes or updates will be made in the annual filings under this schedule.

(M)

SCHEDULE 125 (Continued)

CHANGES IN NET VARIABLE POWER COSTS (M)

Changes in NVPC for purposes of rate determination under this schedule are the projected NVPC as determined in the Annual Power Cost Update less the NVPC revenues that would occur at the NVPC prices determined in the Company's most recent general rate case, adjusted for a revenue sensitive cost factor of 1.0336. (R)(M)

FILING AND EFFECTIVE DATE

On or before April 1st of each calendar year, the Company will file estimates of the adjustments to its NVPC to be effective on January 1st of the following calendar year.

On or before October 1st of each calendar year, the Company will file updated estimates with final planned maintenance outages, final load forecast, updated projections of gas and electric prices, power, and fuel contracts.

On November 15th, the Company will file the final estimate of NVPC and will calculate and file the final change in NVPC to be effective on the next January 1st with: 1) projected market electric and fuel prices based on the average of the Company's internally generated projections made during the period November 1st through November 7th, 2) load reductions from the October update resulting from additional participation in the Company's Long-Term Cost of Service Opt-out that occurs in September, 3) new market power and fuel contracts entered into since the previous updates, and 4) the final planned maintenance outages and load forecast from the October 1st filing.

RATE ADJUSTMENT

The rate adjustment will be based on the Adjusted NVPC less the NVPC revenues that would occur at the NVPC prices determined in the Company's most recent general rate case applied to forecast loads used to determine changes in Net Variable Power Costs. NVPC prices are defined as the price component that recovers the level of NVPC from the Company's most recent general rate case contained in each Schedule's Cost of Service energy prices.

(M)

SCHEDULE 125 (Concluded)

ADJUSTMENT RATES **(T)**

Schedule		Part A ¢ per kWh
7		0.000
15		0.000
32		0.000
38	Large Nonresidential	0.000
47		0.000
49		0.000
75		
	Secondary	0.000 (1)
	Primary	0.000 (1)
	Subtransmission	0.000 (1)
83		0.000
85		
	Secondary	0.000
	Primary	0.000
89		
	Secondary	0.000
	Primary	0.000
	Subtransmission	0.000
91		0.000
92		0.000
95		0.000

(I)(M) **(M)** **(I)**

(1) Applicable only to the Baseline and Scheduled Maintenance Energy. **(T)**

SPECIAL CONDITIONS

1. Costs recovered through this schedule will be allocated to each schedule using the applicable schedule's forecasted energy on the basis of an equal percent of generation revenue applied on a cents per kWh basis to each applicable rate schedule.

SCHEDULE 126
ANNUAL POWER COST VARIANCE MECHANISM

PURPOSE

To recognize in rates part of the difference for a given year between Actual Net Variable Power Costs and the Net Variable Power Costs forecast pursuant to Schedule 125, Annual Power Cost Update and in accordance with Commission Order No. 07-015. This schedule is an "automatic adjustment clause" as defined in ORS 757.210.

APPLICABLE

To all Customers for Electricity Service except those who were served on Schedule 76R and 576R, 485, 489, 515, 532, 538, 549, 583, 585, 589, 591, 592 and 595, or served under Schedules 83, 85 or 89 Daily Price Option for the entire calendar year that the Annual Power Cost Variance accrued. Customers served on Schedules 538, 583, 585, 589, 591, 592 and 595 who received the Schedule 128 Balance of Year Transition Adjustment will be subject to this adjustment.

ANNUAL POWER COST VARIANCE

Subject to the Earnings Test, the Annual Power Cost Variance (PCV) is 90% of the amount that the Annual Variance exceeds either the Positive Annual Power Cost Deadband for a Positive Annual Variance or the Negative Annual Power Cost Deadband for a Negative Annual Variance.

POWER COST VARIANCE ACCOUNT

The Company will maintain a PCV Account to record Annual Variance amounts. The Account will contain the difference between the Adjustment Amount and amounts credited to or collected from Customers. This account will accrue interest at the Commission-authorized rate for deferred accounts. At the end of each year the Adjustment Amount for the calendar year will be adjusted by 50% of the annual interest calculated at the Commission-authorized rate. This amount will be added to the Adjustment Account.

Any balance in the PCV Account will be amortized to rates over a period determined by the Commission. Annually, the Company will propose to the Commission PCV Adjustment Rates that will amortize the PCV to rates over a period recommended by the Company. The amount accruing to Customers, whether positive or negative, will be multiplied by a revenue sensitive factor of 1.0336 to account for franchise fees, uncollectibles, and OPUC fees. (R)

EARNINGS TEST

The recovery from or refund to Customers of any Adjustment Amount will be subject to an earnings review for the year that the power costs were incurred. The Company will recover the Adjustment Amount to the extent that such recovery will not cause the Company's Actual Return on Equity (ROE) for the year to exceed its Authorized ROE minus 100 basis points. The Company will refund the Adjustment Amount to the extent that such refunding will not cause the Company's Actual Return on Equity (ROE) for the year to fall below its Authorized ROE plus 100 basis points.

Schedule 126 (Continued)

DEFINITIONS (Continued)

Net Variable Power Costs (NVPC)

The Net Variable Power Costs (NVPC) represents the power costs for Energy generated and purchased. NVPC are the net cost of fuel and emission control chemicals, fuel and emission control chemical transportation, power contracts, transmission/wheeling, wholesale sales, hedges, options and other financial instruments incurred to serve retail load. For purposes of calculating the NVPC, the following adjustments will be made: **(C)** **(C)**

- Exclude BPA payments in lieu of Subscription Power.
- Exclude the monthly FASB 133 mark-to-market activity.
- Exclude any cost or revenue unrelated to the period.
- Include as a cost all losses that the Company incurs, or is reasonably expected to incur, as a result of any non-retail Customer failing to pay the Company for the sale of power during the deferral period.
- Include fuel costs and revenues associated with steam sales from the Coyote Springs I Plant.
- Include gas resale revenues.
- Include Energy Charge revenues from Schedules 76R, 38, 83, 85, 89, and 91 Energy pricing options other than Cost of Service and the Energy Charge revenues from the Market Based Pricing Option from Schedules 485 and 489 as an offset to NVPC.
- NVPC shall be adjusted as needed to comply with Order 07-015 that states that ancillary services, the revenues from sales as well as the costs from the services, should also be taken into account in the mechanism.
- Actual NVPC will be increased to include the value of the energy associated with those Customers that received the Schedule 128 Balance of Year Transition Adjustment for the period during the year that the Customers received the Schedule 128 adjustment.

ADJUSTMENT AMOUNT

The amount accruing to the Power Cost Variance Account, whether positive or negative will be multiplied by a revenue sensitive factor of 1.0336 to account for franchise fees, uncollectables, and OPUC fees. **(R)**

The Power Cost Adjustment Rate shall be set at level such that the projected amortization for 12 month period beginning with the implementation of the rate is no greater than six percent (6%) of annual Company retail revenues for the preceding calendar year.

TIME AND MANNER OF FILING

As a minimum, on July 1st of the following year (or the next business day if the 1st is a weekend or holiday), the Company will file with the Commission recommended adjustment rates for the next calendar year.

SCHEDULE 128
SHORT-TERM TRANSITION ADJUSTMENT

PURPOSE

The purpose of this Schedule is to calculate the Short-Term Transition Adjustment to reflect the results of the ongoing valuation under OAR 860-038-0140.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all Nonresidential Customers served who receive service at Daily pricing (other than Cost of Service) on Schedules 32, 38, 75, 83, 85, 89, 91 or 95 or Direct Access service on Schedules 515, 532, 538, 549, 575, 583, 585, 589, 591, 592 and 595. This Schedule is not applicable to Customers served on Schedules 485 and 489.

SHORT-TERM TRANSITION ADJUSTMENT

The Short-Term Transition Adjustment will reflect the difference between the Energy Charge(s) under the Cost of Service Option including Schedule 125 and the market price of power for the period of the adjustment applied to the load shape of the applicable schedule.

ANNUAL SHORT-TERM TRANSITION ADJUSTMENT RATE

For Customers who have made a service election other than Cost of Service for 2013, the Annual Short-Term Transition Adjustment Rate will be applied to their bills for service effective on and after January 1, 2014: (C)
(C)

Schedule		Annual ¢ per kWh [1]	
32		2.076	(R)
38		1.984	
75	Secondary	1.108 [2]	(C)
	Primary	1.419 [2]	
	Subtransmission	1.396 [2]	
83		1.964	
85	Secondary	1.771	
	Primary	1.731	(C)(R)

(1) Not applicable to Customers served on Cost of Service.
(2) Applicable only to the Baseline and Scheduled Maintenance Energy.

SCHEDULE 128 (Continued)

ANNUAL SHORT-TERM TRANSITION ADJUSTMENT RATE (Continued)

Schedule		Annual ¢ per kWh (1)	
89	Secondary	1.108	(C)(R)
	Primary	1.419	
	Subtransmission	1.396	
91		1.365	
95		1.365	
515		1.365	
532		2.076	
538		1.984	
549		3.316	
575	Secondary	1.108 (2)	
	Primary	1.419 (2)	
	Subtransmission	1.396 (2)	
583		1.964	
585	Secondary	1.771	
	Primary	1.731	
589	Secondary	1.108	
	Primary	1.419	
	Subtransmission	1.396	
591		1.365	
592		1.315	
595		1.365	(C)(R)

(1) Not applicable to Customers served on Cost of Service.
(2) Applicable only to the Baseline and Scheduled Maintenance Energy.

ANNUAL SHORT-TERM TRANSITION ADJUSTMENT REVISIONS

The Annual Short-Term Transition Adjustment rate will be filed on November 15th (or the next business day if the 15th is a weekend or holiday) to be effective for service on and after January 1st of the next year. Indicative, non-binding estimates for the Annual Short-Term Transition Adjustment and Cost-of-Service Energy Prices will be posted by the Company by September 1 and then again one week prior to the filing date. These prices will be for informational purposes only and are not to be considered the adjustment rates.

SCHEDULE 128 (Concluded)

Second Quarter – April 1st Balance of Year Adjustment Rate [1]

Schedule		Annual ¢ per kWh [2]	
38		0.000	(C)
75	Secondary	0.000 [3]	
	Primary	0.000 [3]	
	Subtransmission	0.000 [3]	
83		0.000	
85	Secondary	0.000	
	Primary	0.000	
89	Secondary	0.000	
	Primary	0.000	
	Subtransmission	0.000	
91		0.000	
95		0.000	
538		0.000	
575	Secondary	0.000 [3]	
	Primary	0.000 [3]	
	Subtransmission	0.000 [3]	
583		0.000	
585	Secondary	0.000	
	Primary	0.000	
589	Secondary	0.000	
	Primary	0.000	
	Subtransmission	0.000	
591		0.000	
592		0.000	(C)
595		0.000	

(C)

(1) Applicable April 1, 2014 through December 31, 2014.
(2) Not applicable to Customers served on Cost of Service.
(3) Applicable only to the Baseline and Scheduled Maintenance Energy.

SCHEDULE 129 (Concluded)

SPECIAL CONDITIONS

1. Annually, the total amount paid in Schedule 129 Long-Term Transition Cost Adjustment will be collected through applicable Large Nonresidential rate schedules (Schedules 75, 76R, 85, 89, 485, 489, 575, 576R, 585, and 589), through either the System Usage or Distribution Charges. Such adjustment to the System Usage or Distribution Charges will be made at the time the Company files final rates for Schedule 125, and will be effective on January 1st of the following calendar year.

2. Annually, changes in fixed generation revenues resulting from either return to or departure from Cost of Service pricing by Schedule 485 and 489 customers relative to the Company's most recent general rate case will be incorporated into the System Usage Charges of the Large Nonresidential Rate Schedules 75, 76R, 85, 89, 485, 489, 575, 576R, 585, and 589. Such adjustment to the System Usage or Distribution Charges will be made at the time the Company files final rates for Schedule 125, and will be effective on January 1st of the following calendar year. The adjustment to the System Usage Charge resulting from changes in fixed generation revenues shall not result in a rate increase or decrease to Schedules 85, and 89 of more than 2 percent except as noted below. For those Enrollment Periods in which the first-year Schedule 129 Transition Adjustments are expected to be positive charges to participants, the projected first-year revenues from Schedule 129 will be netted against the changes in fixed generation costs for purposes of calculating the proposed rate increase or decrease to Schedules 85 and 89. Should the rate increase or decrease for Schedules 85 and 89 exceed 2 percent, the amounts exceeding 2 percent will be deferred for future recovery through a balancing account. This balancing account will be considered an "Automatic Adjustment Clause" as defined in ORS 757.210. For purposes of calculating the percent change in rates, Schedule 125 prices with and without the increased/decreased Schedules 485 and 489 participating load will be determined.

3. In determining changes in fixed generation revenues from movement to or from Schedules 485 and 489, the following factors will be used:

Schedule		¢ per kWh	
85	Secondary	2.335	(I)
	Primary	2.260	
89	Secondary	2.189	
	Primary	2.108	
	Subtransmission	2.079	(I)

TERM

The term of applicability under this schedule will correspond to a Customer's term of service under Schedule 485 or 489.

SCHEDULE 145
BOARDMAN POWER PLANT
DECOMISSIONING ADJUSTMENT (C)

PURPOSE

This schedule establishes the mechanism to implement in rates the revenue requirement effect of the decommissioning expenses related to the Boardman power plant. This schedule is (C) implemented as an "automatic adjustment clause" as defined in ORS 757.210. (C)

APPLICABLE

To all bills for Electricity Service except Schedules 76R, 485, 489 and 576R.

ADJUSTMENT RATES

Schedule 145 Adjustment Rates will be set based an equal percent of Energy Charge revenues applicable at the time of any filing that revises rates pursuant to this schedule.

Schedule	Adjustment Rate	
7	0.014 ¢ per kWh	(R)
15	0.011 ¢ per kWh	
32	0.013 ¢ per kWh	
38	0.013 ¢ per kWh	
47	0.016 ¢ per kWh	
49	0.015 ¢ per kWh	
75		
Secondary	0.011 ¢ per kWh	
Primary	0.011 ¢ per kWh	
Subtransmission	0.011 ¢ per kWh	
83	0.012 ¢ per kWh	
85		
Secondary	0.012 ¢ per kWh	
Primary	0.012 ¢ per kWh	(R)

SCHEDULE 145 (Continued)

ADJUSTMENT RATE (Continued)

Schedule	Adjustment Rate	
89		
Secondary	0.011 ¢ per kWh	(R)
Primary	0.011 ¢ per kWh	
Subtransmission	0.011 ¢ per kWh	
91	0.011 ¢ per kWh	
92	0.011 ¢ per kWh	
95	0.011 ¢ per kWh	(D)
515	0.011 ¢ per kWh	
532	0.013 ¢ per kWh	
538	0.013 ¢ per kWh	
549	0.015 ¢ per kWh	
575		
Secondary	0.011 ¢ per kWh	
Primary	0.011 ¢ per kWh	
Subtransmission	0.011 ¢ per kWh	
583	0.012 ¢ per kWh	
585		
Secondary	0.012 ¢ per kWh	
Primary	0.012 ¢ per kWh	
589		
Secondary	0.011 ¢ per kWh	
Primary	0.011 ¢ per kWh	
Subtransmission	0.011 ¢ per kWh	
591	0.011 ¢ per kWh	
592	0.011 ¢ per kWh	
595	0.011 ¢ per kWh	(R)

SCHEDULE 145 (Concluded)

DETERMINATION OF ADJUSTMENT AMOUNT

(D)

The Adjustment Amount is the revenue requirements related to decommissioning of the Boardman Power Plant using a plant end of life assumption of year-end 2020. The decommissioning revenue requirement computation will use the Commission-authorized tax rates, revenue sensitive cost rates, rate of return and return on equity rates. Only changes to decommissioning expense are included in the revenue requirements. (C) (C)

The Adjustment Rates will be updated annually to reflect the subsequent year's change in the Boardman Power Plant decommissioning revenue requirement. (T)

(D)

BALANCING ACCOUNT

The Company will maintain a balancing account to track the difference between the Schedule 145 Decommissioning Revenue Requirements and the actual Schedule 145 revenues. This difference will accrue interest at the Commission-authorized rate for deferred accounts. (T)

TIME AND MANNER OF FILING

Commencing in 2011, the Company will submit to the Commission the following information by November 1 of each year:

1. The proposed price changes to this Schedule to be effective on January 1st of the following year based on the updated revenue requirements described above.

2. Work papers supporting the Schedule 145 prices, the updated decommissioning revenue requirements, the projected applicable billing determinants, and the projected balancing account activity. (T)

SCHEDULE 485
LARGE NONRESIDENTIAL
COST OF SERVICE OPT-OUT
(201 - 4,000 kW) **(C)**

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has exceeded 200 kW more than six times in the preceding 13 months but has not exceeded 4,000 kW more than once in the preceding 13 **(C)** months, or with seven months or less of service has not had a Demand exceeding 4,000 kW and **(C)** who has chosen the Company's transition plan during one of the enrollment periods specified below. To obtain service under this schedule, Customers must enroll a minimum of 1 MWa determined by a demonstrated usage pattern such that projected usage for a full 12 months is at least 8,760,000 kWh (1 MWa) from one or more Points of Delivery (POD). Each POD must have a Facility Capacity of at least 250 kW. Service under this schedule is limited to the first 300 MWa that applies to this and Schedule 489. Beginning with the September 2004 Enrollment Period C, Customers have a minimum five-year option and a fixed three-year option.

ENROLLMENT PERIODS

ENROLLMENT PERIODS	MINIMUM FIVE-YEAR OPTION
Enrollment Period A:	January 1, 2003 through December 31, 2007
Enrollment Period B:	January 1, 2004 through December 31, 2008
Enrollment Period C:	January 1, 2005 through December 31, 2009
Enrollment Period D:	January 1, 2006 through December 31, 2010
Enrollment Period E:	January 1, 2007 through December 31, 2011
Enrollment Period F:	January 1, 2008 through December 31, 2012
Enrollment Period G:	January 1, 2009 through December 31, 2013
Enrollment Period H:	January 1, 2010 through December 31, 2014
Enrollment Period I:	January 1, 2011 through December 31, 2015
Enrollment Period J:	January 1, 2012 through December 31, 2016
Enrollment Period K:	January 1, 2013 through December 31, 2017

SCHEDULE 485 (Continued)

CHANGE IN APPLICABILITY

If a Customer's usage changes such that their facility capacity falls below 201 kW, they will have their service terminated under this schedule and will be moved to an otherwise applicable schedule.

MONTHLY RATE

The Monthly Rate will be the sum of the following charges at the applicable Delivery Voltage per POD*:

	Delivery Voltage		
	Secondary	Primary	
Basic Charge	\$370.00	\$390.00	(I)
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 200 kW	\$3.12	\$3.04	(I)
Over 200 kW	\$2.12	\$2.04	(R)(I)
per kW of monthly On-Peak Demand	\$2.05	\$1.99	(I)
System Usage Charge			
per kWh	0.042 ¢	0.040 ¢	(R)

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the POD.

MARKET BASED PRICING OPTION

Energy Supply

The Customer may elect to purchase Energy from an Electricity Service Supplier (ESS) (Direct Access Service) or from the Company. Such election will be for all of the Customer's POD under this schedule.

Direct Access Service

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS.

SCHEDULE 485 (Continued)

MARKET BASED PRICING OPTION (Continued)

Company Supplied Energy

Upon not less than five business days notice, the Customer may choose the Company Supplied Energy Charge option. The election of this option will be effective on the next regularly scheduled meter reading date, but with not less than a five business day notice to the Company prior to the scheduled meter read date.

The Company Supplied Energy Option is the Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Index) plus 2 mills per kWh plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported.

Wheeling Charge

The Wheeling Charge will be $1.713 per kW of monthly Demand. **(I)**

Transmission Charge

Transmission and Ancillary Service Charges will be as specified in the Company's Open Access Transmission Tariff (OATT) as filed and approved by the Federal Energy Regulatory Commission.

FACILITY CAPACITY

The Facility Capacity will be the average of the two greatest non-zero monthly Demands established anytime during the 12-month period which includes and ends with the current Billing Period.

MINIMUM CHARGE

The minimum charge will be the Basic and Distribution Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher minimum charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in Facilities. The minimum monthly On-Peak Demand (in kW) will be 100 kW for primary voltage service.

SCHEDULE 489
LARGE NONRESIDENTIAL
COST-OF-SERVICE OPT-OUT
(>4,000 kW) **(C)**

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has exceeded 4,000 kW more than once within the preceding 13 months and who has chosen the Company's transition plan during one of the enrollment periods specified below. To obtain service under this schedule, Customers must enroll a minimum of 1 MWa determined by a demonstrated usage pattern such that projected usage for a full 12 months is at least 8,760,000 kWh (1 MWa) from one or more Points of Delivery (POD). Each POD must have a Facility Capacity of at least 250 kW. Service under this schedule is limited to the first 300 MWa that applies to this and Schedule 485. Beginning with the September 2004 Enrollment Period C, Customers have a minimum five-year option and a fixed three-year option. **(C)**

ENROLLMENT PERIODS

ENROLLMENT PERIODS	MINIMUM FIVE-YEAR OPTION
Enrollment Period A:	January 1, 2003 through December 31, 2007
Enrollment Period B:	January 1, 2004 through December 31, 2008
Enrollment Period C:	January 1, 2005 through December 31, 2009
Enrollment Period D:	January 1, 2006 through December 31, 2010
Enrollment Period E:	January 1, 2007 through December 31, 2011
Enrollment Period F:	January 1, 2008 through December 31, 2012
Enrollment Period G:	January 1, 2009 through December 31, 2013
Enrollment Period H:	January 1, 2010 through December 31, 2014
Enrollment Period I:	January 1, 2011 through December 31, 2015
Enrollment Period J:	January 1, 2012 through December 31, 2016
Enrollment Period K:	January 1, 2013 through December 31, 2017

SCHEDULE 489 (Continued)

MONTHLY RATE

The Monthly Rate will be the sum of the following charges at the applicable Delivery Voltage per POD*:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge	$4,850.00	$4,460.00	$5,130.00	(I)
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.90	$1.85	$1.85	
Over 4,000 kW	$1.26	$1.21	$1.21	
per kW of monthly On-Peak Demand	$2.05	$1.99	$1.12	(I)
System Usage Charge				
per kWh	0.020 ¢	0.019 ¢	0.018 ¢	(R)

* See Schedule 100 for applicable adjustments.
** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the POD.

MARKET BASED PRICING OPTION

Energy Supply

The Customer may elect to purchase Energy from an Electricity Service Supplier (ESS) (Direct Access Service) or from the Company. Such election will be for all of the Customer's POD under this schedule.

Direct Access Service

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, Transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS.

SCHEDULE 489 (Continued)

MARKET BASED PRICING OPTION (Continued)

Company Supplied Energy

Upon not less than five business days notice, the Customer may choose the Company Supplied Energy Charge option. The election of this option will be effective on the next regularly scheduled meter reading date, but with not less than a five business day notice to the Company prior to the scheduled meter read date.

The Company Supplied Energy Option is the Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Index) plus 2 mills per kWh plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported.

Wheeling Charge

The Wheeling Charge will be $1.713 per kW of monthly Demand. **(I)**

Transmission Charge

Transmission and Ancillary Service Charges will be as specified in the Company's Open Access Transmission Tariff (OATT) as filed and approved by the Federal Energy Regulatory Commission.

MINIMUM CHARGE

The minimum charge will be the Basic and Distribution Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher minimum charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in Facilities. The minimum Facility Capacity and Demand (in kW) will be 200 kW and 4,000 kW for primary voltage and subtransmission voltage service respectively.

ON AND OFF PEAK HOURS

On-peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

SCHEDULE 515
OUTDOOR AREA LIGHTING
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Nonresidential Customers purchasing Direct Access Service for outdoor area lighting.

CHARACTER OF SERVICE

Lighting services, which consist of the provision of Company-owned luminaires mounted on Company-owned poles, in accordance with Company specifications as to equipment, installation, maintenance and operation.

The Company will replace lamps on a scheduled basis. Subject to the Company's operating schedules and requirements, the Company will replace individual burned-out lamps as soon as reasonably possible after the Customer or Electricity Service Supplier (ESS) notifies the Company of the burn-out.

MONTHLY RATE

Rates for Area Lighting

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate(1) Per Luminaire	
Cobrahead					
Mercury Vapor	175	7,000	66	$ 9.22 (2)	(I)
	400	21,000	147	13.18 (2)	
	1,000	55,000	374	24.29 (2)	
HPS	70	6,300	30	7.70 (2)	
	100	9,500	43	8.24	
	150	16,000	62	9.13	
	200	22,000	79	10.06	
	250	29,000	102	11.26	
	310	37,000	124	12.65 (2)	
	400	50,000	163	14.41	
Flood , HPS	100	9,500	43	8.27 (2)	
	200	22,000	79	10.96 (2)	
	250	29,000	102	12.05	
	400	50,000	163	14.80	
Shoebox, HPS (bronze color, flat lens, or drop lens, multi-volt)	70	6,300	30	9.15	
	100	9,500	43	9.93	
	150	16,500	62	11.10	(I)

(1) See Schedule 100 for applicable adjustments.
(2) No new service.

SCHEDULE 515 (Continued)

MONTHLY RATE (Continued)

Rates for Area Lighting (Continued)

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate(1) Per Luminaire	
Special Acorn Type, HPS	100	9,500	43	$12.91	(I)
HADCO Victorian, HPS	150	16,500	62	13.78	
	200	22,000	79	15.32	
	250	29,000	102	16.39	
Early American Post-Top, HPS, Black	100	9,500	43	9.01	(I)
Special Types					
Cobrahead, Metal Halide	150	10,000	60	9.66	(R)
Cobrahead, Metal Halide	175	12,000	71	10.45	(I)
Flood, Metal Halide	350	30,000	139	15.15	(R)
Flood, Metal Halide	400	40,000	156	14.71	(I)
Flood, HPS	750	105,000	285	23.89	
HADCO Independence, HPS	100	9,500	43	13.04	
	150	16,000	62	13.57	
HADCO Capitol Acorn, HPS	100	9,500	43	17.02	
	150	16,000	62	17.94	
	200	22,000	79	18.58	
	250	29,000	102	19.64	
HADCO Techtra, HPS	100	9,500	43	22.16	
	150	16,000	62	22.68	(I)
	250	29,000	102	23.85	(R)
HADCO Westbrooke, HPS	70	6,300	30	15.37	
	100	9,500	43	15.72	
	150	16,000	62	16.60	
	200	22,000	79	17.66	
	250	29,000	102	18.59	(R)
KIM Archetype, HPS	250	29,000	102	21.58	(I)
	400	50,000	163	19.15	
Holophane Mongoose, HPS	150	16,000	62	14.26	
	250	29,000	102	15.38	(I)
					(D)

(1) See Schedule 100 for applicable adjustments.

SCHEDULE 515 (Continued)

MONTHLY RATE (Continued)
Rates for Area Light Poles[1]

Type of Pole	Pole Length (feet)	Monthly Rate Per Pole	
Wood, Standard	35 or less	$ 7.40	(I)
	40 to 55	9.70	(C)
Wood, Painted Underground	35 or less	7.40 [2]	
Wood, Curved laminated	30 or less	9.19 [2]	
Aluminum, Regular	16	8.86	
	25	14.70	
	30	15.89	
	35	19.02	(I)
Aluminum, Fluted Ornamental	14	12.99	(R)
Aluminum Davit	25	13.60	(I)
	30	14.60	
	35	15.97	
	40	21.68	
Aluminum Double Davit	30	21.58	(I)
Aluminum, HADCO, Fluted Ornamental	16	13.28	(R)
Aluminum, HADCO, Non-fluted	18	25.57	(I)
Concrete, Ameron Post-Top	25	25.51	(R)
Fiberglass Fluted Ornamental; Black	14	15.70	(I)
Fiberglass, Regular			
Black,	20	6.51	
Gray or Bronze;	30	11.07	
Other Colors (as available)	35	9.53	
Fiberglass, Anchor Base Gray	35	17.45	
Fiberglass, Direct Bury with Shroud	18	10.50	(I)

(1) No pole charge for luminaires placed on existing Company-owned distribution poles.
(2) No new service.

INSTALLATION CHARGE

See Schedule 300 regarding the installation of conduit on wood poles.

SCHEDULE 532
SMALL NONRESIDENTIAL
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Small Nonresidential Customers who have chosen to receive Electricity from an Electricity Service Supplier (ESS).

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge		
Single Phase	$14.00	(I)
Three Phase	$18.00	
Distribution Charge		
First 5,000 kWh	4.241 ¢ per kWh	(I)
Over 5,000 kWh	0.673 ¢ per kWh	(R)

* See Schedule 100 for applicable adjustments.

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 538
LARGE NONRESIDENTIAL OPTIONAL TIME-OF-DAY DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

This optional schedule is applicable to Large Nonresidential Customers who have chosen to receive service from an Electricity Service Supplier (ESS), and: 1) served at Secondary voltage with a monthly Demand that does not exceed 200 kW more than once in the preceding 13 months; or 2) who were receiving service on Schedule 38 as of December 31, 2006.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge			
Single Phase Service	$25.00		(I)
Three Phase Service	$25.00		
Distribution Charge	6.163	¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.

MINIMUM CHARGE

The Minimum Charge will be the Basic Charge. In Addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge if necessary, to justify the Company's investment in service facilities.

REACTIVE DEMAND

In addition to the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 549
IRRIGATION AND DRAINAGE PUMPING
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers who have chosen to receive Electricity from an Electricity Service Supplier (ESS) for irrigation and drainage pumping; may include other incidental service if an additional meter would otherwise be required.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge		
Summer Months**	$35.00	(I)
Winter Months**	No Charge	
Distribution Charge		
First 50 kWh per kW of Demand	4.248 ¢ per kWh	(I)
Over 50 kWh per kW of Demand	2.248 ¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.
** Summer Months and Winter Months commence with meter readings as defined in Rule B.

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

SCHEDULE 575
PARTIAL REQUIREMENTS SERVICE
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers who receive Electricity Service from an Electricity Service Supplier (ESS) and who supply all or some portion of their load by self generation operating on a regular basis, where the self-generation has a total nameplate rating of 2 MW or greater. A Large Nonresidential Customer is a Customer that has exceeded 30 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 30 kW.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Point of Delivery (POD)*:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge				
Three Phase Service	$4,850.00	$4,460.00	$5,130.00	(I)
Distribution Charge				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.90	$1.85	$1.85	
Over 4,000 kW	$1.26	$1.21	$1.21	
per kW of monthly On-Peak Demand**	$2.05	$1.99	$1.12	(I)
Generation Contingency Reserves Charges***				
Spinning Reserves				
per kW of Reserved Capacity > 1,000 kW	$0.234	$0.234	$0.234	
Supplemental Reserves				
per kW of Reserved Capacity > 1,000 kW	$0.234	$0.234	$0.234	
System Usage Charge				
per kWh	0.020 ¢	0.019 ¢	0.018 ¢	(R)

* See Schedule 100 for applicable adjustments.

** Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

*** Not applicable when ESS is providing Energy Regulation and Imbalance services as described in Schedule 600.

SCHEDULE 576R
ECONOMIC REPLACEMENT POWER RIDER
DIRECT ACCESS SERVICE

PURPOSE

To provide Customers served on Schedule 575 with the option for delivery of Energy from the Customer's Electricity Service Supplier (ESS) to replace some, or all of the Customer's on-site generation when the Customer deems it is more economically beneficial than self generating.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers served on Schedule 575.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHY RATE

The following charges are in addition to applicable charges under Schedule 575:*

	Secondary	Primary	Subtransmission	
Daily Economic Replacement Power (ERP) Demand Charge				
per kW of Daily ERP Demand during On-Peak hours per day**	$0.080	$0.078	$0.044	(I)
System Usage Charge				
per kWh of ERP	0.020 ¢	0.019 ¢	0.018 ¢	(R)
Transaction Fee				
per Energy Needs Forecast (ENF) submission or revision	$50.00	$50.00	$50.00	

* See Schedule 100 for applicable adjustments.
** Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

SCHEDULE 583
LARGE NONRESIDENTIAL DIRECT ACCESS SERVICE
(31 – 200 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customers whose Demand has not exceeded 200 kW more than six times in the preceding 13 months and has not exceeded 1,000 kW more than once in the preceding 13 months, or with seven months or less of service has not had a Demand exceeding 1,000 kW and who has chosen to receive Electricity from an Electricity Service Supplier (ESS).

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Point of Delivery (POD)*:

<u>Basic Charge</u>		
Single Phase Service	$30.00	(I)
Three Phase Service	$40.00	
<u>Distribution Charges</u>**		
The sum of the following:		
per kW of Facility Capacity		
First 30 kW	$2.98	
Over 30 kW	$2.48	
per kW of monthly Demand	$2.05	
<u>System Usage Charge</u>		
per kWh	0.691 ¢	(I)

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the POD.

SCHEDULE 585
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE
(201 – 4,000 kW) (C)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customers whose Demand has exceeded 200 kW more than six times in the preceding 13 months and has not exceeded 4,000 kW more than once in the preceding (C) 13 months, or with seven months or less of service has not had a Demand exceeding 4,000 kW and (C) who has chosen to receive Electricity from an Electricity Service Supplier (ESS).

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Point of Delivery (POD)*:

	Delivery Voltage		
	Secondary	Primary	
Basic Charge	$370.00	$390.00	(I)
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 200 kW	$3.12	$3.04	(I)
Over 200 kW	$2.12	$2.04	(R)(I)
per kW of monthly On-Peak Demand	$2.05	$1.99	(I)
System Usage Charge			
per kWh	0.042 ¢	0.040 ¢	(R)

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the POD.

SCHEDULE 589
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE
(>4,000 kW) (C)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has exceeded 4,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 4,000 kW, and who has chosen to receive Electricity from an ESS. (C)

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Point of Delivery (POD)*:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge	$4,850.00	$4,460.00	$5,130.00	(I)
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.90	$1.85	$1.85	
Over 4,000 kW	$1.26	$1.21	$1.21	
per kW of monthly on-peak Demand	$2.05	$1.99	$1.12	(I)
System Usage Charge				
per kWh	0.020 ¢	0.019 ¢	0.018 ¢	(R)

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the POD.

SCHEDULE 591 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)
Option A - Luminaire (Continued)

The Customer is responsible for repair or replacement of luminaires and circuits damaged as a result of rotted wood poles owned by the Customer. **(N)** **(N)**

The Company may remove or discontinue service to any luminaire and related equipment that has become unsafe or unsatisfactory for further service by reason of deterioration, storm, flood, and lightning, proximity to interference by trees or structures, or other causes as determined by the Company. The Company will notify the Customer as soon as reasonably practical of any such service discontinuation and luminaire replacement schedule.

Option B - Luminaire

Option B provides electricity service to Customer purchased and owned luminaires at the monthly Option B rate applicable to the installed type of light.

The Company does not at any time assume ownership of Option B luminaires.

As defined herein, the Company provides for maintenance only to luminaires and related equipment at the applicable monthly Option B rate. The Company will replace non-repairable Option B luminaires for which the Customer is charged and billed the appropriate replacement costs (1), in addition to the applicable monthly Option B rate.

Maintenance Service under Option B

Includes preventative group lamp replacement and glassware cleaning subject to the Company's operating schedule.

Maintenance under Option B luminaires specifically does not include replacement of failed or failing ballasts or replacement of luminaires that are deemed inoperable due to general deterioration, lack of replacement parts, or replacement of parts associated with Emergency Repair that will not bring the unit into operable status. Such inoperable luminaires will be designated as non-repairable luminaires. This exclusion does not include replacements of Power Doors where the Customer is qualified and paying the applicable Cobrahead Power Door rate. In addition, Maintenance under Option B luminaires excludes maintenance related to vegetation management, luminaire relocation or modification of the luminaire (such as adding light shields).

(1) Replacement costs include: Installation Labor + Material costs and loading + Removal Labor = total billable charges. For applicable labor rates, refer to page 591-6 of this Schedule.

SCHEDULE 591 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)

Option C – Luminaire

Option C provides electricity service to luminaires that are purchased, owned and maintained by the Customer and installed on Customer-owned poles. As a condition to the election of Option C, Customer is responsible for ensuring that all new underground service installations of Option C luminaires are isolated by a disconnect switch or fuse. Both the equipment used to isolate the luminaire and its location must be approved by the Company. **(C)**

Maintenance Service under Option C

The Company does not maintain Customer-purchased lighting when mounted on Customer-owned poles. Such maintenance and service is the sole responsibility of the Customer.

Special Provisions for Option B to Option C Luminaire Conversion and Future Maintenance Election

1. The Company will, with not less than 180 days written notice from the Customer (the requesting municipality) and subject to completion of all conditions necessary to finalize such election, convert the entirety of the Customer's lighting service under Option B luminaire lighting rates to the equivalent Option C luminaires lighting rates (with respect to Monthly kWh usage) including Option B luminaires attachment to Company-owned poles.

2. Upon such conversion, the Customer will assume all on-going maintenance responsibilities for the luminaires and associated circuits in accordance with this schedule's provisions for Option C luminaires. The Customer may not require that the Company provide new Option B lighting following the conversion to Option C luminaires. The Customer must notify and inform all affected residents of the conversion that all maintenance and repair services are the sole responsibility of the Customer, and not the Company.

3. The Customer may choose the Schedule 91 Option B to Schedule 95 Option C Luminaire Conversion and Future Maintenance Election as described in Schedule 95 if converting to Schedule 95 Option C luminaires and the above notice has not been given. **(T)**

SCHEDULE 591 (Continued)

STREETLIGHT POLES SERVICE OPTIONS (Continued)
Option B – Pole maintenance (Continued)

Emergency Pole Replacement and Repair

The Company will repair or replace damaged streetlight poles that have been damaged due to the acts of vandalism, damage claim incidences and storm related events that cause a pole to become structurally unsound at no additional cost to the customer.

Without notice to the Customer, individual poles that are damaged or destroyed by unexpected events will be replaced on determination that the pole is unfit for further use as soon as reasonably possible. Replacement is subject to the Company's operating schedules and requirements.

Special Provisions for Option B - Poles

1. If damage occurs to any streetlighting pole more than two times in any 12-month period measured from the first incidence of damage that requires replacement, the Customer will be responsible to pay for future installations or mutually agree with the Company and pay to have the pole either completely removed or relocated.

2. Non-Standard or Custom poles are provided at the Company's discretion to allow greater flexibility in the choice of equipment. The Company will not maintain an inventory of this equipment and thus delays in maintenance may occur. The Company will order and replace the equipment subject to availability since non-standard and custom equipment is subject to obsolescence. The Customer will pay for any additional cost to the Company for ordering non-standard equipment.

MONTHLY RATE

The service rates for Option A and B lights include the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Distribution Charge	4.548 ¢ per kWh	**(I)**
Energy Charge	Provided by Energy Service Supplier	

NOVEMBER ELECTION WINDOW

The November Election Window begins at 2:00 p.m. on November 15th (or the following business day if the 15th falls on a weekend or holiday). The November Election Window will remain open until 5:00 p.m. at the close of the fifth consecutive business day.

During a November Election Window, a Customer may notify the Company of its choice to change to any service options for an effective date of January 1st. Customers may notify the Company of a choice to change service options using the Company's website, PortlandGeneral.com/business

SCHEDULE 591 (Continued)

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rates [1]	Straight Time	Overtime
	$120.00 per hour	$167.00 per hour

(1) Per Article 20.2 of the Collective Bargaining Agreement Union No. 125 Contract, overtime is paid at the Overtime Rate for a minimum of one hour.

RATES FOR STANDARD LIGHTING
High-Pressure Sodium (HPS) Only – Service Rates

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Cobrahead Power Doors **							
	70	6,300	30	*	$ 2.64	$ 1.36	(R)(I)
	100	9,500	43	*	3.25	1.96	
	150	16,000	62	*	4.12	2.82	
	200	22,000	79	*	4.95	3.59	
	250	29,000	102	*	6.01	4.64	
	400	50,000	163	*	8.80	7.41	
Cobrahead, Non-Power Door	70	6.300	30	$ 6.56	2.89	1.36	
	100	9,500	43	7.10	3.48	1.96	
	150	16,000	62	7.99	4.35	2.82	
	200	22,000	79	9.39	5.17	3.59	
	250	29,000	102	10.58	6.25	4.64	
	400	50,000	163	13.73	9.05	7.41	
Flood	250	29,000	102	11.37	6.34	4.64	
	400	50,000	163	14.13	9.10	7.41	
Early American Post-Top	100	9,500	43	7.88	3.56	1.96	
Shoebox (Bronze color, flat	70	6,300	30	8.01	3.06	1.36	
Lens, or drop lens, multi-volt)	100	9,500	43	8.79	3.68	1.96	(R)(I)
	150	16,000	62	9.96	4.59	2.82	

* Not offered.
** Service is only available to customers with total power doors luminaires in excess of 2,500.

SCHEDULE 591 (Continued)

RATES FOR STANDARD POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Fiberglass, Black	20	$ 6.51	$ 0.19	(I)
Fiberglass, Bronze	30	10.26	0.29	
Fiberglass, Gray	30	11.07	0.32	
Wood, Standard	30 to 35	7.40	0.21	
Wood, Standard	40 to 55	9.70	0.28	(I)

RATES FOR CUSTOM LIGHTING

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	Monthly Rates Option C	
Special Acorn-Types							
HPS	100	9,500	43	$12.23	$ 4.04	$ 1.96	(R)(I)
HADCO Victorian, HPS	150	16,000	62	13.11	4.92	2.82	
	200	22,000	79	14.65	5.81	3.59	
	250	29,000	102	15.71	6.86	4.64	
HADCO Capitol Acorn, HPS	100	9,500	43	16.35	4.52	1.96	
	150	16,000	62	17.26	5.43	2.82	
	200	22,000	79	17.90	6.19	3.59	
	250	29,000	102	18.97	7.25	4.64	
Special Architectural Types							
HADCO Independence, HPS	100	9,500	43	12.36	4.04	1.96	
	150	16,000	62	12.89	4.87	2.82	
HADCO Techtra, HPS	100	9,500	43	21.48	5.10	1.96	
	150	16,000	62	22.01	5.94	2.82	
	250	29,000	102	23.17	7.72	4.64	
HADCO Westbrooke, HPS	70	6,300	30	14.70	3.79	1.36	
	100	9,500	43	15.05	4.36	1.96	
	150	16,000	62	15.92	5.23	2.82	
	200	22,000	79	16.98	6.07	3.59	
	250	29,000	102	17.91	7.11	4.64	(R)(I)

* Not offered.

SCHEDULE 591 (Continued)

RATES FOR CUSTOM LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Types							
Cobrahead, Metal Halide	150	10,000	60	$ 8.53	$ 4.57	$ 2.73	(R)(I)
Flood, Metal Halide	350	30,000	139	14.48	8.47	6.32	
Flood, HPS	750	105,000	285	23.21	15.65	12.96	
Holophane Mongoose, HPS	150	16,000	62	13.59	4.97	2.82	
	250	29,000	102	14.71	6.73	4.64	(R)(I)
							(D)
Option C Only **							
Ornamental Acorn Twin	85	9,600	64	*	*	2.91	(I)
Ornamental Acorn	55	2,800	21	*	*	0.96	
Ornamental Acorn Twin	55	5,600	42	*	*	1.91	
Composite, Twin	140	6,815	54	*	*	2.46	
	175	9,815	66	*	*	3.00	(I)

RATES FOR CUSTOM POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Aluminum, Regular	16	$ 8.86	$ 0.25	(I)(R)
	25	14.70	0.42	
	30	15.89	0.45	
	35	19.02	0.54	
Aluminum Davit	25	14.67	0.42	
	30	14.60	0.42	
	35	15.97	0.46	
	40	21.68	0.62	
Aluminum Double Davit	30	21.58	0.62	
Aluminum, HADCO, Fluted Victorian Ornamental	14	12.99	0.37	(I)

* Not offered.
** Rates are based on current kWh energy charges.

SCHEDULE 591 (Continued)

RATES FOR CUSTOM POLES (Continued)

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Aluminum, HADCO, Non-Fluted Techtra Ornamental	18	$25.57	$ 0.73	(I)
Aluminum, HADCO, Fluted Ornamental	16	13.28	0.38	
Aluminum, HADCO, Non-Fluted Ornamental Westbrooke	16	27.18	0.78	
Aluminum, HADCO, Fluted Westbrooke	18	25.64	0.73	
Aluminum, HADCO, Non-Fluted, Westbrooke	18	27.18	0.78	
Aluminum, Painted Ornamental	35	43.67	1.25	(I)
Concrete, Decorative Ameron	20	25.51	0.73	(R)
Concrete, Ameron Post-Top	25	25.51	0.73	(I)
Fiberglass, HADCO, Fluted Ornamental Black	14	15.70	0.45	
Fiberglass, Smooth	18	6.48	0.19	
Fiberglass, Regular,				
color may vary	22	5.80	0.17	
color may vary	35	9.53	0.27	
Fiberglass, Anchor Base, Gray	35	17.45	0.50	
Fiberglass, Direct Bury with Shroud	18	10.50	0.30	(I)

(D)

SERVICE RATE FOR OBSOLETE LIGHTING

The following equipment is <u>not</u> available for new installations under Options A and B. To the extent feasible, maintenance will be provided. Obsolete Lighting will be replaced with the Customer's choice of Standard or Custom equipment. The Customer will then be billed at the appropriate Standard or Custom rate. If an existing mercury vapor luminaire requires the replacement of a ballast, the unit will be replaced with a corresponding HPS unit.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Cobrahead, Mercury Vapor	100	4,000	39	*	*	$ 1.77	(I)
	175	7,000	66	$ 8.08	$ 4.46	3.00	(R)(I)
	250	10,000	94	*	*	4.28	(R)(I)
	400	21,000	147	12.51	8.29	6.69	(I)
	1,000	55,000	374	23.61	18.93	17.01	(I)

* Not offered.

SCHEDULE 591 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Box Similar to GE "Space-Glo"							
HPS	70	6,300	30	$ 8.09	$ 2.98	$ 1.36	(R)
Mercury Vapor	175	7,000	66	9.68	4.57	3.00	(R)(I)
Special box, Anodized Aluminum							
Similar to GardCo Hub							
HPS	Twin 70	6,300	60	*	*	2.73	
	70	6,300	30	*	*	1.36	
	100	9,500	43	*	3.93	1.96	
	150	16,000	62	*	4.81	2.82	
	250	29,000	102	*	*	4.64	
	400	50,000	163	*	*	7.41	
Metal Halide	250	20,500	99	*	5.70	4.50	
	400	40,000	156	*	8.29	7.09	
Cobrahead, Metal Halide	175	12,000	71	9.31	4.92	3.23	
Flood, Metal Halide	400	40,000	156	14.03	8.83	7.09	
Cobrahead, Dual Wattage HPS							
70/100 Watt Ballast	100	9,500	43	*	3.49	1.96	
100/150 Watt Ballast	100	9,500	43	*	3.49	1.96	
100/150 Watt Ballast	150	16,000	62	*	4.37	2.82	(M)
Special Architectural Types Including Philips QL Induction Lamp Systems							
HADCO Victorian, QL	85	6,000	32	*	2.13	1.46	
	165	12,000	60	*	3.67	2.73	
HADCO Techtra, QL	165	12,000	60	25.95	3.87	2.73	(M)
Special Architectural Types							
KIM SBC Shoebox, HPS	150	16,000	62	*	5.37	2.82	(R)(I)
KIM Archetype, HPS	250	29,000	102	*	7.45	4.64	(I)
	400	50,000	163	*	9.61	7.41	(I)

* Not offered

SCHEDULE 591 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Acorn-Type, HPS	70	6,300	30	$11.61	$ 3.42	$ 1.36	(R)(I)
Special GardCo Bronze Alloy							
HPS	70	5,000	30	*	*	1.36	(I)
Mercury Vapor	175	7,000	66	*	*	3.00	
Special Acrylic Sphere							
Mercury Vapor	400	21,000	147	*	*	6.69	(I)
Early American Post-Top, HPS							
Black	70	6,300	30	7.17	2.85	1.36	(R)(I)
Rectangle Type	200	22,000	79	*	*	3.59	
Incandescent	92	1,000	31	*	*	1.41	
	182	2,500	62	*	*	2.82	(I)
Town and Country Post-Top							
Mercury Vapor	175	7,000	66	8.82	4.50	3.00	(R)(I)
Flood, HPS	70	6,300	30	6.56	2.94	1.36	
	100	9,500	43	7.13	3.48	1.96	
	200	22,000	79	10.28	5.25	3.59	(R)(I)
Cobrahead, HPS							
Power Door	310	37,000	124	11.97	7.64	5.64	(I)
Special Types Customer-Owned & Maintained							
Ornamental, HPS	100	9,500	43	*	*	1.96	
Twin ornamental, HPS	Twin 100	9,500	86	*	*	3.91	
Compact Fluorescent	28	N/A	12	*	*	0.55	(I)

* Not offered.

SCHEDULE 591 (Continued)

RATES FOR OBSOLETE LIGHTING POLES

Type of Pole	Poles Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Aluminum Post	30	$ 8.86	*	(I)
Bronze Alloy GardCo	12	*	$ 0.23	(R)
Concrete, Ornamental	35 or less	14.70	0.42	
Steel, Painted Regular **	25	14.70	0.42	
Steel, Painted Regular **	30	15.89	0.45	
Steel, Unpainted 6-foot Mast Arm **	30	*	0.42	
Steel, Unpainted 6-foot Davit Arm **	30	*	0.42	
Steel, Unpainted 8-foot Mast Arm **	35	*	0.46	
Steel, Unpainted 8-foot Davit Arm **	35	*	0.46	
Wood, Laminated without Mast Arm	20	6.51	0.19	
Wood, Laminated Street Light Only	20	6.51	*	
Wood, Curved Laminated	30	10.26	0.29	
Wood, Painted Underground	35	7.40	0.21	
Wood, Painted Street Light Only	35	7.40	*	(I)

* Not offered.
** Maintenance does not include replacement of rusted steel poles. (D)
(M)

SCHEDULE 591 (Continued)

SPECIAL CONDITIONS (Continued)

5. If circuits or poles not already covered under Special Condition 2 or 3 are removed or relocated at the Customer's request, the Customer is responsible for all associated costs for labor and materials incurred when fulfilling this request.

6. For Option C lights: The Company does not provide the circuit on new installations. **(C)**

7. For Option C lights in service prior to January 31, 2006: When the Company furnishes Electricity to luminaires owned and maintained by the Customer and installed on Customer-owned poles that are not included in the list of equipment in this schedule, usage for the luminaire will be estimated by the Company. When the Customer and the Company cannot agree, the Commission will determine the estimate usage.

8. For Option A and Option B lights: The Company shall not be liable when either (i) the luminaires become inoperable or (ii) repair or replacement of inoperable luminaires is delayed or prevented; provided that, such inoperability of the luminaires or delay or prevention of repair or replacement is due to any cause beyond the Company's control, or that otherwise could not reasonably be foreseen or guarded against including but not limited to such causes as: strikes, lockouts, labor troubles, riots, insurrection, war, acts of God, extreme weather conditions, access to equipment, or the like.

9. For Option C lights: The Customer must ensure that (i) all maintenance and other work associated with this schedule is in compliance with the applicable requirements of OSHA, OPUC Safety Rules, the NESC and/or NEC and (ii) that all such work is performed by a Qualified Worker. A "Qualified Worker" means one who is knowledgeable about the construction and operation of the electric power generation, transmission, and distribution equipment as it relates to his or her work, along with the associated hazards, as demonstrated by satisfying the qualifying requirements for a "qualified person" or "qualified employee" with regard to the work in question as described in 29 CFR 1910.269 effective January 31, 1994, as it may be amended from time to time. In this case, a Qualified Worker is a journeyman lineman, or someone who has the equivalent training, expertise and experience to perform journeyman lineman work.

SCHEDULE 592
TRAFFIC SIGNALS
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments served on Schedule 92, who purchase Electricity from an Electricity Service Supplier (ESS) for traffic signals and warning facilities in systems containing at least 50 intersections on public streets and highways, where funds for payment of Electricity are provided through taxation or property assessment. This schedule is available only to those governmental agencies receiving service under Schedule 92 as of September 30, 2001.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The charge per Point of Delivery (POD)* is:

Distribution Charge	2.078 ¢ per kWh	(R)

* See Schedule 100 for applicable adjustments.

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 595
STREET AND HIGHWAY LIGHTING
NEW TECHNOLOGY
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments purchasing Direct Access for lighting service utilizing Company approved streetlighting equipment for public streets and highways and public grounds where funds for payment of Electricity are provided through taxation or property assessment.

CHARACTER OF SERVICE

From dusk to dawn daily, controlled by a photoelectric control to be mutually agreeable to the Customer and Company for an average of 4,100 hours annually.

LUMINAIRE SERVICE OPTIONS - The Company offers the following Luminaire Service Options at the applicable rates specified herein.

The Customer will elect the Luminaire Service Option at the time of initial luminaire installation.

Option A - Luminaire

Option A provides electricity service to luminaires that are purchased, owned, and maintained by the Company with attachment to Company-owned poles at the monthly Option A rate applicable to the installed type of light.

Maintenance Service under Option A

The Company will only perform emergency maintenance on the luminaires listed in this schedule. The Company does not perform preventative maintenance on the luminaires listed in this schedule.

The Company will repair or replace inoperable luminaires as soon as reasonably possible, subject to the Company's operating schedule, following notification to PGE's Customer Service or PGE's Outdoor Lighting Services[1] department by the Customer, a member of the public, or a PGE employee performing luminaire replacement work. PGE has no obligation for repair or replacement of inoperable luminaires other than as described in this section of the tariff. (C)

(1) Contact PGE's Outdoor Lighting Services at 503-736-5710, PGE's Customer Service 503-228-6322 or 1- 800-542-8818, or www.portlandgeneral.com to report an inoperable streetlight.

SCHEDULE 595 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)
Maintenance Service under Option A (Continued)

The Customer is responsible for repair or replacement of luminaires and circuits damaged as a result of rotted wood poles owned by the Customer. **(N)** **(N)**

The Company may remove or discontinue service to any luminaire and related equipment that has become unsafe or unsatisfactory for further service by reason of deterioration, storm, flood, and lightning, proximity to interference by trees or structures, or other causes as determined by the Company. The Company will notify the Customer as soon as reasonably practical of any such service discontinuation.

Option C – Luminaire

Option C provides electricity service to luminaires that are purchased, owned and maintained by the Customer and installed on Customer-owned poles. As a condition to the election of Option C, Customer is responsible for ensuring that all new underground service installations of Option C luminaires are isolated by a disconnect switch or fuse. Both the equipment used to isolate the luminaire and its location must be approved by the Company. The Company may provide necessary circuits for an additional charge.

Maintenance Service under Option C

The Company has no obligation to maintain Customer-purchased lighting if the Customer selects this option. Such maintenance and service is the sole responsibility of the Customer.

Special Provisions for Schedule 91/591 Option B to Schedule 95/595 Option C Luminaire Conversion and Future Maintenance Election

1. If Customer elects to convert any of its luminaires from Schedule 91 Option B to Schedule 95 Option C, the Customer must at the same time commit to convert the entirety of Customer's Schedule 91 Option B luminaires to Schedules 91 Option C and Schedule 95 Option C using one of two methods: (A) within five years following PGE's group lamp replacement cycle or (B) within three years on a schedule mutually agreed upon between the Company and Customer. Customer may elect to have some of its luminaires on Schedule 91 Option C and some on Schedule 95 Option C.

2. Upon such conversion, the Customer will assume and bear the cost of all on-going maintenance responsibilities for the luminaires and associated circuits in accordance with this schedule's provisions for Option C luminaires from the date each luminaire is converted to Option C. After the three or five year period, any remaining Option B luminaires will be converted to Option C. The Company may not provide new Option B lighting under Schedule 91 following the election to convert any Option B luminaires to Schedule 91 or Schedule 95 Option C luminaires.

SCHEDULE 595 (Continued)

STREETLIGHT POLES SERVICE OPTIONS

Option A – Poles

See Schedule 91/591 for Streetlight poles service options.

MONTHLY RATE

The service rates for Option A lights include the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Distribution Charge — 4.548 ¢ per kWh (I)

Energy Charge — Provided by Energy Service Supplier

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rates [1]	Straight Time	Overtime
	$120.00 per hour	$167.00 per hour

(1) Per Article 20.2 of the Collective Bargaining Agreement Union No. 125 Contract, overtime is paid at the Overtime Rate for a minimum of one hour.

RATES FOR STANDARD LIGHTING

Light-Emitting Diode (LED) Only – Option A Service Rates

LED lighting is new to the Company and pricing is changing rapidly. The Company may adjust rates under this schedule based on actual frequency of maintenance occurrences and changes in material prices.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rate Option A	
LED	37	2,530	13	$4.05	(R)
LED	50	3,162	17	4.23	
LED	52	3,757	18	4.70	
LED	67	5,050	23	5.41	
LED	106	7,444	36	6.86	(R)

SCHEDULE 595 (Continued)

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

NOVEMBER ELECTION WINDOW

The November Election Window begins at 2:00 p.m. on November 15th (or the following business day if the 15th falls on a weekend or holiday). The November Election Window will remain open until 5:00 p.m. at the close of the fifth consecutive business day.

During a November Election Window, a Customer may notify the Company of its choice to change to any service options for an effective date of January 1st. Customers may notify the Company of a choice to change service options using the Company's website, PortlandGeneral.com/business

SPECIAL CONDITIONS

1. The Company may periodically offer temporary or experimental lighting equipment that is not otherwise listed in this rate schedule. Temporary or experimental lighting will be offered at a billing rate based on approved prices for near equivalent lighting service equipment. The use of temporary or experimental lighting will be for a limited duration not to exceed one year at which time the lighting service equipment will either be removed or the Company will file with the Commission to add the luminaire type to this rate schedule.

2. Customer is responsible for the cost associated with trenching, boring, conduit and restoration required for underground service to streetlighting.

3. Unless otherwise specifically provided, the location of Company-owned streetlighting equipment and poles may be changed at the Customer's request and upon payment by the Customer of the costs of removal and reinstallation.

4. If Company-owned streetlighting equipment or poles are removed at the Customer's request, a charge will be made consisting of the estimated original cost, less depreciation, less salvage value, plus removal cost. This provision does not pertain to the sale of Company-owned equipment. This condition applies if a Customer's selection of service under this Schedule requires the removal of Company-owned streetlighting equipment or poles.

5. If circuits or poles not already covered under Special Condition 2 or 3 are removed or relocated at the Customer's request, the Customer is responsible for all associated costs for labor and materials incurred when fulfilling this request.

6. For Option C lights: The Company does not provide the circuit on new installations. (C)

TABLE 1
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS
2014

CATEGORY	RATE SCHEDULE	Forecast SDEC12E14 CUSTOMERS	MWH SALES	TOTAL ELECTRIC BILLS CURRENT w/ Sch. 122a, 125, 145	TOTAL ELECTRIC BILLS PROPOSED w/ Sch. 122a, 125, 145	Change AMOUNT	Change PCT.
Residential	7	734,050	7,542,460	$833,489,226	$905,895,872	$72,406,646	8.7%
Employee Discount				($902,971)	($983,049)	($80,078)	
Subtotal				$832,586,255	$904,912,823	$72,326,568	8.7%
Outdoor Area Lighting	15	0	23,112	$4,165,014	$4,816,987	$651,974	15.7%
General Service <30 kW	32	88,797	1,580,824	$161,910,848	$178,995,232	$17,084,384	10.6%
Opt. Time-of-Day G.S. >30 kW	38	300	30,898	$3,713,920	$3,997,763	$283,843	7.6%
Irrig. & Drain. Pump. < 30 kW	47	3,203	21,482	$2,904,287	$3,398,224	$493,938	17.0%
Irrig. & Drain. Pump. > 30 kW	49	1,296	68,174	$6,471,840	$7,572,871	$1,101,031	17.0%
General Service 31-200 kW	83	11,129	2,796,682	$233,790,883	$248,421,577	$14,630,694	6.3%
General Service 201-4,000 kW							
Secondary	85-S	1,258	2,478,641	$187,571,498	$191,995,062	$4,423,564	2.4%
Primary	85-P	192	686,547	$48,130,495	$49,715,036	$1,584,541	3.3%
Schedule 89 > 4 MW							
Secondary	89-S	2	18,273	$1,432,410	$1,522,896	$90,486	6.3%
Primary	89-P	23	2,191,332	$135,205,728	$133,995,513	($1,210,216)	-0.9%
Subtransmission	89-T	5	204,501	$12,568,482	$12,640,246	$71,764	0.6%
Street & Highway Lighting	91/95	205	102,931	$17,468,466	$18,190,933	$722,467	4.1%
Traffic Signals	92	17	4,439	$337,738	$337,383	($355)	-0.1%
COS TOTALS		840,477	17,750,295	$1,648,257,862	$1,760,512,545	$112,254,682	6.8%
Direct Access Service 201-4,000 kW							
Secondary	485-S	158	434,943	$12,489,353	$9,803,787	($2,685,566)	
Primary	485-P	42	227,560	$7,013,157	$5,338,923	($1,674,234)	
Direct Access Service > 4 MW							
Primary	489-P	8	491,720	$8,880,647	$6,960,210	($1,920,437)	
Subtransmission	489-T	3	329,357	$5,249,769	$3,957,796	($1,291,973)	
DIRECT ACCESS TOTALS		211	1,483,580	$33,632,926	$26,060,717	($7,572,209)	
COS AND DA CYCLE TOTALS		840,688	19,233,875	$1,681,890,788	$1,786,573,262	$104,682,473	6.2%

TABLE 2
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS
2014

CATEGORY	RATE SCHEDULE	CUSTOMERS (Forecast SDEC12E14)	MWH SALES	TOTAL ELECTRIC BILLS CURRENT w/ Sch. 122a, 125, 145, 102	TOTAL ELECTRIC BILLS PROPOSED w/ Sch. 122a, 125, 145, 102	Change AMOUNT	Change PCT.
Residential	7	734,050	7,542,460	$776,348,355	$848,755,001	$72,406,646	9.3%
Employee Discount				($845,985)	($926,063)	($80,078)	
Subtotal				$775,502,370	$847,828,938	$72,326,568	9.3%
Outdoor Area Lighting	15	0	23,112	$4,114,475	$4,766,449	$651,974	15.8%
General Service <30 kW	32	88,797	1,580,824	$160,180,261	$177,264,645	$17,084,384	10.7%
Opt. Time-of-Day G.S. >30 kW	38	300	30,898	$3,711,122	$3,994,964	$283,843	7.6%
Irrig. & Drain. Pump. < 30 kW	47	3,203	21,482	$2,761,872	$3,255,810	$493,938	17.9%
Irrig. & Drain. Pump. > 30 kW	49	1,296	68,174	$6,044,782	$7,145,813	$1,101,031	18.2%
General Service 31-200 kW	83	11,129	2,796,682	$232,053,953	$246,684,648	$14,630,694	6.3%
General Service 201-4,000 kW							
Secondary	85-S	1,258	2,478,641	$187,174,823	$191,598,387	$4,423,564	2.4%
Primary	85-P	192	686,547	$48,072,912	$49,657,453	$1,584,541	3.3%
Schedule 89 > 4 MW							
Secondary	89-S	2	18,273	$1,432,410	$1,522,896	$90,486	6.3%
Primary	89-P	23	2,191,332	$135,205,728	$133,995,513	($1,210,216)	-0.9%
Subtransmission	89-T	5	204,501	$12,568,482	$12,640,246	$71,764	0.6%
Street & Highway Lighting	91/95	205	102,931	$17,468,466	$18,190,933	$722,467	4.1%
Traffic Signals	92	17	4,439	$337,738	$337,383	($355)	-0.1%
COS TOTALS		840,477	17,750,295	$1,586,629,393	$1,698,884,076	$112,254,682	7.1%
Direct Access Service 201-4,000 kW							
Secondary	485-S	158	434,943	$12,489,353	$9,803,787	($2,685,566)	
Primary	485-P	42	227,560	$7,013,157	$5,338,923	($1,674,234)	
Direct Access Service > 4 MW							
Primary	489-P	8	491,720	$8,880,647	$6,960,210	($1,920,437)	
Subtransmission	489-T	3	329,357	$5,249,769	$3,957,796	($1,291,973)	
DIRECT ACCESS TOTALS		211	1,483,580	$33,632,926	$26,060,717	($7,572,209)	
COS AND DA CYCLE TOTALS		840,688	19,233,875	$1,620,262,319	$1,724,944,793	$104,682,473	6.5%

TABLE 3
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS
2014

CATEGORY	RATE SCHEDULE	Forecast SDEC12E14 CUSTOMERS	MWH SALES	TOTAL ELECTRIC BILLS CURRENT all supplementals except LIA, PPC & Sch 109	TOTAL ELECTRIC BILLS PROPOSED all supplementals except LIA, PPC & Sch 109	Change AMOUNT	Change PCT.
Residential	7	734,050	7,542,460	$776,951,752	$850,188,069	$73,236,317	9.4%
Employee Discount				($847,592)	($927,669)	($80,078)	
Subtotal				$776,104,161	$849,260,399	$73,156,239	9.4%
Outdoor Area Lighting	15	0	23,112	$4,110,595	$4,764,649	$654,054	15.9%
General Service <30 kW	32	88,797	1,580,824	$157,557,737	$174,800,203	$17,242,466	10.9%
Opt. Time-of-Day G.S. >30 kW	38	300	30,898	$3,703,115	$3,990,036	$286,921	7.7%
Irrig. & Drain. Pump. < 30 kW	47	3,203	21,482	$2,758,435	$3,254,736	$496,301	18.0%
Irrig. & Drain. Pump. > 30 kW	49	1,296	68,174	$6,027,745	$7,136,275	$1,108,530	18.4%
General Service 31-200 kW	83	11,129	2,796,682	$231,330,770	$246,241,133	$14,910,363	6.4%
General Service 201-4,000 kW							
Secondary	85-S	1,258	2,478,641	$186,603,205	$191,249,847	$4,646,642	2.5%
Primary	85-P	192	686,547	$47,941,540	$49,587,870	$1,646,330	3.4%
Schedule 89 > 4 MW							
Secondary	89-S	2	18,273	$1,428,207	$1,520,338	$92,131	6.5%
Primary	89-P	23	2,191,332	$134,688,976	$133,675,981	($1,012,996)	-0.8%
Subtransmission	89-T	5	204,501	$12,519,401	$12,609,570	$90,169	0.7%
Street & Highway Lighting	91/95	205	102,931	$17,445,821	$18,177,552	$731,730	4.2%
Traffic Signals	92	17	4,439	$336,451	$336,495	$44	0.0%
COS TOTALS		840,477	17,750,295	$1,582,556,159	$1,696,605,083	$114,048,924	7.2%
Direct Access Service 201-4,000 kW							
Secondary	485-S	158	434,943	$12,454,958	$9,769,392	($2,685,566)	
Primary	485-P	42	227,560	$6,996,703	$5,322,469	($1,674,234)	
Direct Access Service > 4 MW							
Primary	489-P	8	491,720	$8,826,418	$6,905,981	($1,920,437)	
Subtransmission	489-T	3	329,357	$5,236,595	$3,944,622	($1,291,973)	
DIRECT ACCESS TOTALS		211	1,483,580	$33,514,673	$25,942,464	($7,572,209)	
COS AND DA CYCLE TOTALS		840,688	19,233,875	$1,616,070,832	$1,722,547,547	$106,476,715	6.6%

TABLE 4
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS
2014

		Forecast SDEC12E14		TOTAL ELECTRIC BILLS			
				CURRENT with all supplementals except LIA & PPC	PROPOSED with all supplementals except LIA & PPC	Change	
CATEGORY	**RATE SCHEDULE**	CUSTOMERS	MWH SALES			AMOUNT	PCT.
Residential	7	734,050	7,542,460	$804,858,853	$878,095,169	$73,236,317	9.1%
Employee Discount				($847,592)	($927,669)	($80,078)	
Subtotal				$804,011,261	$877,167,500	$73,156,239	9.1%
Outdoor Area Lighting	15	0	23,112	$4,251,840	$4,905,894	$654,054	15.4%
General Service <30 kW	32	88,797	1,580,824	$162,976,771	$180,219,237	$17,242,466	10.6%
Opt. Time-of-Day G.S. >30 kW	38	300	30,898	$3,827,005	$4,113,926	$286,921	7.5%
Irrig. & Drain. Pump. < 30 kW	47	3,203	21,482	$2,855,529	$3,351,829	$496,301	17.4%
Irrig. & Drain. Pump. > 30 kW	49	1,296	68,174	$6,244,859	$7,353,389	$1,108,530	17.8%
General Service 31-200 kW	83	11,129	2,796,682	$239,119,502	$254,029,865	$14,910,363	6.2%
General Service 201-4,000 kW							
Secondary	85-S	1,258	2,478,641	$192,381,691	$197,028,333	$4,646,642	2.4%
Primary	85-P	192	686,547	$48,836,273	$50,482,604	$1,646,330	3.4%
Schedule 89 > 4 MW							
Secondary	89-S	2	18,273	$1,428,207	$1,520,338	$92,131	6.5%
Primary	89-P	23	2,191,332	$134,688,976	$133,675,981	($1,012,996)	-0.8%
Subtransmission	89-T	5	204,501	$12,519,401	$12,609,570	$90,169	0.7%
Street & Highway Lighting	91/95	205	102,931	$18,004,738	$18,736,469	$731,730	4.1%
Traffic Signals	92	17	4,439	$347,814	$347,858	$44	0.0%
COS TOTALS		840,477	17,750,295	$1,631,493,868	$1,745,542,792	$114,048,924	7.0%
Direct Access Service 201-4,000 kW							
Secondary	485-S	158	434,943	$13,177,354	$10,491,789	($2,685,566)	
Primary	485-P	42	227,560	$7,303,525	$5,629,292	($1,674,234)	
Direct Access Service > 4 MW							
Primary	489-P	8	491,720	$8,826,418	$6,905,981	($1,920,437)	
Subtransmission	489-T	3	329,357	$5,236,595	$3,944,622	($1,291,973)	
DIRECT ACCESS TOTALS		211	1,483,580	$34,543,892	$26,971,683	($7,572,209)	
COS AND DA CYCLE TOTALS		840,688	19,233,875	$1,666,037,760	$1,772,514,475	$106,476,715	6.4%

PORTLAND GENERAL ELECTRIC
Effect of proposed rate change on Monthly Bills
Tariff Schedule 7

kWh	Net Monthly Bill Current Prices	Proposed Prices	Percent Difference
50	$14.92	$16.39	9.9%
100	$19.71	$21.60	9.6%
200	$29.28	$32.08	9.6%
250	$34.09	$37.32	9.5%
300	$38.86	$42.54	9.5%
400	$48.43	$53.02	9.5%
500	$58.03	$63.48	9.4%
600	$67.61	$73.89	9.3%
700	$77.20	$84.38	9.3%
800	$86.77	$94.83	9.3%
900	$96.35	$105.32	9.3%
1,000	$105.92	$115.76	9.3%
1,100	$117.21	$127.92	9.1%
1,200	$128.48	$140.09	9.0%
1,300	$139.78	$152.26	8.9%
1,400	$151.04	$164.42	8.9%
1,500	$162.35	$176.61	8.8%
1,600	$173.63	$188.73	8.7%
1,700	$184.92	$200.90	8.6%
1,800	$196.20	$213.07	8.6%
2,000	$218.75	$237.39	8.5%
2,300	$252.60	$273.89	8.4%
2,750	$303.39	$328.63	8.3%
3,000	$331.58	$359.03	8.3%
3,500	$388.01	$419.88	8.2%
4,000	$444.41	$480.66	8.2%
4,500	$500.84	$541.51	8.1%
5,000	$557.24	$602.30	8.1%
7,500	$839.32	$906.42	8.0%
10,000	$1,121.38	$1,210.47	7.9%

PORTLAND GENERAL ELECTRIC
Effect of proposed rate change on Monthly Bills
Tariff Schedule 32, 1-phase Service

	Net Monthly Billing (without RPA credit)			Net Monthly Billing (with RPA credit)		
kWh	Current Prices	Proposed Prices	Percent Difference	Current Prices	Proposed Prices	Percent Difference
500	$63.01	$70.63	12.1%	$59.22	$66.84	12.9%
600	$73.11	$81.85	12.0%	$68.57	$77.30	12.7%
700	$83.23	$93.09	11.8%	$77.93	$87.79	12.7%
800	$93.38	$104.31	11.7%	$87.32	$98.25	12.5%
900	$103.50	$115.57	11.7%	$96.68	$108.75	12.5%
1,000	$113.63	$126.81	11.6%	$106.05	$119.24	12.4%
1,500	$164.27	$183.02	11.4%	$152.91	$171.66	12.3%
1,750	$189.57	$211.11	11.4%	$176.33	$197.86	12.2%
2,000	$214.89	$239.20	11.3%	$199.75	$224.06	12.2%
2,500	$265.54	$295.41	11.2%	$246.61	$276.48	12.1%
3,500	$366.80	$407.80	11.2%	$340.30	$381.29	12.0%
4,000	$417.42	$463.98	11.2%	$387.14	$433.69	12.0%
4,500	$468.07	$520.19	11.1%	$434.00	$486.11	12.0%
5,000	$518.69	$576.37	11.1%	$480.83	$538.51	12.0%
6,000	$594.08	$652.00	9.7%	$548.65	$606.58	10.6%
7,000	$669.47	$727.64	8.7%	$616.47	$674.65	9.4%
8,000	$744.86	$803.28	7.8%	$684.30	$742.72	8.5%
9,000	$820.25	$878.92	7.2%	$752.12	$810.78	7.8%
10,000	$895.64	$954.56	6.6%	$819.94	$878.85	7.2%
14,000	$1,197.21	$1,257.11	5.0%	$1,091.22	$1,151.13	5.5%
15,000	$1,272.60	$1,332.75	4.7%	$1,159.04	$1,219.19	5.2%
20,000	$1,649.56	$1,710.94	3.7%	$1,498.15	$1,559.53	4.1%
21,900	$1,792.80	$1,854.66	3.5%	$1,627.00	$1,688.86	3.8%

PORTLAND GENERAL ELECTRIC
Effect of proposed rate change on Monthly Bills
Tariff Schedule 32, 3-phase Service

	Net Monthly Bill (without RPA credit)			Net Monthly Bill (with RPA credit)		
kWh	Current Prices	Proposed Prices	Percent Difference	Current Prices	Proposed Prices	Percent Difference
500	$67.13	$74.75	11.4%	$63.34	$70.96	12.0%
600	$77.23	$85.97	11.3%	$72.69	$81.42	12.0%
700	$87.35	$97.21	11.3%	$82.05	$91.91	12.0%
800	$97.50	$108.43	11.2%	$91.44	$102.37	12.0%
900	$107.62	$119.69	11.2%	$100.80	$112.87	12.0%
1,000	$117.75	$130.93	11.2%	$110.17	$123.36	12.0%
1,500	$168.39	$187.14	11.1%	$157.03	$175.78	11.9%
1,750	$193.69	$215.23	11.1%	$180.45	$201.98	11.9%
2,000	$219.01	$243.32	11.1%	$203.87	$228.18	11.9%
2,500	$269.66	$299.53	11.1%	$250.73	$280.60	11.9%
3,500	$370.92	$411.92	11.1%	$344.42	$385.41	11.9%
4,000	$421.54	$468.10	11.0%	$391.26	$437.81	11.9%
4,500	$472.19	$524.31	11.0%	$438.12	$490.23	11.9%
5,000	$522.81	$580.49	11.0%	$484.95	$542.63	11.9%
6,000	$598.20	$656.12	9.7%	$552.77	$610.70	10.5%
7,000	$673.59	$731.76	8.6%	$620.59	$678.77	9.4%
8,000	$748.98	$807.40	7.8%	$688.42	$746.84	8.5%
9,000	$824.37	$883.04	7.1%	$756.24	$814.90	7.8%
10,000	$899.76	$958.68	6.5%	$824.06	$882.97	7.1%
14,000	$1,201.33	$1,261.23	5.0%	$1,095.34	$1,155.25	5.5%
15,000	$1,276.72	$1,336.87	4.7%	$1,163.16	$1,223.31	5.2%
20,000	$1,653.68	$1,715.06	3.7%	$1,502.27	$1,563.65	4.1%
21,900	$1,796.92	$1,858.78	3.4%	$1,631.12	$1,692.98	3.8%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 47 Summer Period

		Net Monthly Bill (without RPA credit)			Net Monthly Bill (with RPA credit)		
kW	kWh	Current Prices	Proposed Prices	Percent Difference	Current Prices	Proposed Prices	Percent Difference
10	50	$32.46	$38.58	18.9%	$32.08	$38.19	19.0%
10	100	$39.16	$46.23	18.1%	$38.39	$45.47	18.4%
10	500	$92.83	$107.58	15.9%	$89.04	$103.79	16.6%
10	1,000	$149.59	$173.94	16.3%	$142.02	$166.37	17.1%
10	2,000	$263.13	$306.67	16.5%	$247.99	$291.53	17.6%
10	5,000	$603.75	$704.86	16.7%	$565.90	$667.01	17.9%
20	100	$39.16	$46.23	18.1%	$38.39	$45.47	18.4%
20	200	$52.57	$61.57	17.1%	$51.06	$60.06	17.6%
20	500	$92.83	$107.58	15.9%	$89.04	$103.79	16.6%
20	1,000	$159.89	$184.23	15.2%	$152.32	$176.66	16.0%
20	2,000	$273.43	$316.96	15.9%	$258.29	$301.82	16.9%
20	5,000	$614.05	$715.15	16.5%	$576.20	$677.30	17.5%
20	8,000	$954.68	$1,113.34	16.6%	$894.11	$1,052.77	17.7%
30	150	$45.87	$53.91	17.5%	$44.74	$52.78	18.0%
30	500	$92.83	$107.58	15.9%	$89.04	$103.79	16.6%
30	1,000	$159.89	$184.23	15.2%	$152.32	$176.66	16.0%
30	3,000	$397.27	$460.00	15.8%	$374.56	$437.29	16.7%
30	5,000	$624.35	$725.46	16.2%	$586.50	$687.61	17.2%
30	8,000	$964.98	$1,123.65	16.4%	$904.41	$1,063.08	17.5%
30	10,000	$1,192.06	$1,389.11	16.5%	$1,116.35	$1,313.40	17.7%
30	15,000	$1,759.76	$2,052.76	16.6%	$1,646.20	$1,939.20	17.8%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 49 Summer Period

			Net Monthly Bill (without RPA credit)			Net Monthly Bill (with RPA credit)		
Load Factor	kW	kWh	Current Prices	Proposed Prices	Percent Difference	Current Prices	Proposed Prices	Percent Difference
20%	35	5,110	$532.67	$620.40	16.5%	$493.98	$581.71	17.8%
40%	35	10,220	$998.38	$1,168.67	17.1%	$921.01	$1,091.30	18.5%
60%	35	15,330	$1,464.09	$1,716.97	17.3%	$1,348.03	$1,600.91	18.8%
80%	35	20,440	$1,929.80	$2,265.26	17.4%	$1,775.06	$2,110.52	18.9%
20%	50	7,300	$747.70	$870.84	16.5%	$692.43	$815.57	17.8%
40%	50	14,600	$1,413.00	$1,654.10	17.1%	$1,302.47	$1,543.57	18.5%
60%	50	21,900	$2,078.32	$2,437.39	17.3%	$1,912.52	$2,271.59	18.8%
80%	50	29,200	$2,743.61	$3,220.66	17.4%	$2,522.55	$2,999.60	18.9%
20%	70	10,220	$1,034.43	$1,204.73	16.5%	$957.06	$1,127.36	17.8%
40%	70	20,440	$1,965.85	$2,301.32	17.1%	$1,811.11	$2,146.59	18.5%
60%	70	30,660	$2,897.26	$3,397.89	17.3%	$2,665.15	$3,165.78	18.8%
80%	70	40,880	$3,828.67	$4,494.47	17.4%	$3,519.19	$4,184.99	18.9%
20%	100	14,600	$1,464.49	$1,705.59	16.5%	$1,353.96	$1,595.06	17.8%
40%	100	29,200	$2,795.10	$3,272.15	17.1%	$2,574.04	$3,051.09	18.5%
60%	100	43,800	$4,125.70	$4,838.69	17.3%	$3,794.11	$4,507.10	18.8%
80%	100	58,400	$5,456.32	$6,405.24	17.4%	$5,014.20	$5,963.13	18.9%
20%	200	29,200	$2,898.10	$3,375.15	16.5%	$2,677.04	$3,154.09	17.8%
40%	200	58,400	$5,559.32	$6,508.24	17.1%	$5,117.20	$6,066.13	18.5%
60%	200	87,600	$8,220.49	$9,641.32	17.3%	$7,557.31	$8,978.14	18.8%
80%	200	116,800	$10,881.70	$12,774.42	17.4%	$9,997.47	$11,890.18	18.9%

PORTLAND GENERAL ELECTRIC
Effect of proposed rate change on Monthly Bills
Tariff Schedule 38, 3-phase Service
Bill comparison assumes 51% on peak and 49% off peak energy consumption

	Net Monthly Bill (without RPA credit)			Net Monthly Bill (with RPA credit)		
kWh	Current Prices	Proposed Prices	Percent Difference	Current Prices	Proposed Prices	Percent Difference
1,000	$148.56	$159.26	7.2%	$140.99	$151.69	7.6%
3,000	$394.15	$426.27	8.1%	$371.44	$403.56	8.6%
5,000	$639.75	$693.29	8.4%	$601.90	$655.44	8.9%
7,000	$885.36	$960.31	8.5%	$832.37	$907.31	9.0%
10,000	$1,253.76	$1,360.83	8.5%	$1,178.06	$1,285.13	9.1%
13,000	$1,622.17	$1,761.36	8.6%	$1,523.75	$1,662.94	9.1%
14,000	$1,744.97	$1,894.86	8.6%	$1,638.98	$1,788.88	9.1%
16,000	$1,990.57	$2,161.88	8.6%	$1,869.44	$2,040.75	9.2%
21,000	$2,604.57	$2,829.42	8.6%	$2,445.59	$2,670.44	9.2%
25,000	$3,095.79	$3,363.46	8.6%	$2,906.52	$3,174.20	9.2%
30,000	$3,709.79	$4,030.99	8.7%	$3,482.67	$3,803.88	9.2%
35,000	$4,323.79	$4,698.53	8.7%	$4,058.82	$4,433.57	9.2%
40,000	$4,937.80	$5,366.07	8.7%	$4,634.98	$5,063.25	9.2%
45,000	$5,551.80	$6,033.61	8.7%	$5,211.13	$5,692.94	9.2%
50,000	$6,165.82	$6,701.16	8.7%	$5,787.30	$6,322.63	9.3%
75,000	$9,235.84	$10,038.87	8.7%	$8,668.05	$9,471.08	9.3%
100,000	$12,305.88	$13,376.56	8.7%	$11,548.83	$12,619.51	9.3%
150,000	$18,445.95	$20,051.97	8.7%	$17,310.37	$18,916.39	9.3%
200,000	$24,586.00	$26,727.37	8.7%	$23,071.90	$25,213.27	9.3%
300,000	$36,866.13	$40,078.18	8.7%	$34,594.98	$37,807.03	9.3%
400,000	$49,146.25	$53,428.99	8.7%	$46,118.05	$50,400.79	9.3%
500,000	$61,426.38	$66,779.80	8.7%	$57,641.13	$62,994.55	9.3%
750,000	$89,172.60	$97,202.73	9.0%	$83,494.72	$91,524.85	9.6%
1,000,000	$118,888.20	$129,595.05	9.0%	$111,317.70	$122,024.55	9.6%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 83, Secondary, 3 phase service.

			Net Monthly Billing (without RPA credit)			Net Monthly Bill (with RPA credit)		
Load Factor	kW	kWh	Current Prices	Proposed Prices	Percent Difference	Current Prices	Proposed Prices	Percent Difference
30%	30	6,570	$650.78	$703.29	8.1%	$601.04	$653.55	8.7%
30%	50	10,950	$1,057.86	$1,134.40	7.2%	$974.97	$1,051.51	7.9%
30%	75	16,425	$1,566.69	$1,673.25	6.8%	$1,442.35	$1,548.91	7.4%
30%	100	21,900	$2,075.55	$2,212.12	6.6%	$1,909.75	$2,046.32	7.2%
30%	135	29,565	$2,787.90	$2,966.54	6.4%	$2,564.08	$2,742.72	7.0%
30%	175	38,325	$3,602.05	$3,828.71	6.3%	$3,311.91	$3,538.57	6.8%
30%	200	43,800	$4,110.89	$4,367.59	6.2%	$3,779.30	$4,036.00	6.8%
50%	30	10,950	$961.87	$1,022.96	6.4%	$878.97	$940.06	7.0%
50%	50	18,250	$1,576.32	$1,667.13	5.8%	$1,438.15	$1,528.97	6.3%
50%	75	27,375	$2,344.39	$2,472.37	5.5%	$2,137.14	$2,265.13	6.0%
50%	100	36,500	$3,112.44	$3,277.60	5.3%	$2,836.12	$3,001.28	5.8%
50%	135	49,275	$4,187.75	$4,404.94	5.2%	$3,814.71	$4,031.91	5.7%
50%	175	63,875	$5,416.66	$5,693.33	5.1%	$4,933.10	$5,209.76	5.6%
50%	200	73,000	$6,184.73	$6,498.57	5.1%	$5,632.08	$5,945.92	5.6%
70%	30	15,330	$1,272.92	$1,342.59	5.5%	$1,156.86	$1,226.53	6.0%
70%	50	25,550	$2,094.78	$2,199.87	5.0%	$1,901.36	$2,006.45	5.5%
70%	75	38,325	$3,122.07	$3,271.48	4.8%	$2,831.93	$2,981.34	5.3%
70%	100	51,100	$4,149.36	$4,343.11	4.7%	$3,762.51	$3,956.25	5.1%
70%	135	68,985	$5,587.61	$5,843.36	4.6%	$5,065.35	$5,321.11	5.0%
70%	175	89,425	$7,231.27	$7,557.95	4.5%	$6,554.28	$6,880.96	5.0%
70%	200	102,200	$8,258.57	$8,629.55	4.5%	$7,484.86	$7,855.85	5.0%
90%	30	19,710	$1,584.01	$1,662.24	4.9%	$1,434.79	$1,513.02	5.5%
90%	50	32,850	$2,613.24	$2,732.62	4.6%	$2,364.54	$2,483.93	5.0%
90%	75	49,275	$3,899.76	$4,070.61	4.4%	$3,526.73	$3,697.57	4.8%
90%	100	65,700	$5,186.28	$5,408.60	4.3%	$4,688.90	$4,911.21	4.7%
90%	135	88,695	$6,987.42	$7,281.75	4.2%	$6,315.95	$6,610.29	4.7%
90%	175	114,975	$9,045.87	$9,422.56	4.2%	$8,175.45	$8,552.13	4.6%
90%	200	131,400	$10,332.42	$10,760.55	4.1%	$9,337.65	$9,765.78	4.6%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 85, Secondary, 3 phase service.
Bill Comparison assumes 60% on-peak, 40% off-peak energy consumption

			Net Monthly Bill		
Load Factor	kW	kWh	Current Prices	Proposed Prices	Percent Difference
30%	200	43,800	$4,111.18	$4,410.09	7.3%
30%	300	65,700	$6,015.39	$6,321.59	5.1%
30%	500	109,500	$9,823.76	$10,144.58	3.3%
30%	700	153,300	$13,632.12	$13,967.55	2.5%
30%	800	175,200	$15,536.32	$15,879.03	2.2%
30%	900	197,100	$17,440.51	$17,790.53	2.0%
30%	1,000	219,000	$19,344.68	$19,702.02	1.8%
30%	1,500	328,500	$28,500.76	$29,259.50	2.7%
30%	2,000	438,000	$37,575.27	$38,816.94	3.3%
30%	4,000	876,000	$72,026.57	$74,867.12	3.9%
50%	200	73,000	$5,989.54	$6,265.21	4.6%
50%	300	109,500	$8,832.90	$9,104.28	3.1%
50%	500	182,500	$14,519.62	$14,782.38	1.8%
50%	700	255,500	$20,206.33	$20,460.49	1.3%
50%	800	292,000	$23,049.67	$23,299.53	1.1%
50%	900	328,500	$25,893.04	$26,138.60	0.9%
50%	1,000	365,000	$28,736.39	$28,977.63	0.8%
50%	1,500	547,500	$42,148.70	$43,172.92	2.4%
50%	2,000	730,000	$55,772.53	$57,368.17	2.9%
50%	4,000	1,460,000	$106,959.89	$110,286.46	3.1%
70%	200	102,200	$7,867.89	$8,120.33	3.2%
70%	300	153,300	$11,650.40	$11,886.95	2.0%
70%	500	255,500	$19,215.47	$19,420.19	1.1%
70%	700	357,700	$26,780.53	$26,953.41	0.6%
70%	800	408,800	$30,563.03	$30,720.02	0.5%
70%	900	459,900	$34,345.57	$34,486.65	0.4%
70%	1,000	511,000	$38,128.09	$38,253.25	0.3%
70%	1,500	766,500	$54,180.70	$55,179.13	1.8%
70%	2,000	1,022,000	$71,804.21	$73,365.45	2.2%
70%	4,000	2,044,000	$141,831.21	$145,643.81	2.7%
90%	200	131,400	$9,746.22	$9,975.46	2.4%
90%	300	197,100	$14,467.93	$14,669.63	1.4%
90%	500	328,500	$23,911.32	$24,058.00	0.6%
90%	700	459,900	$33,354.71	$33,446.35	0.3%
90%	800	525,600	$38,076.41	$38,140.50	0.2%
90%	900	591,300	$42,798.11	$42,834.69	0.1%
90%	1,000	657,000	$47,519.80	$47,528.86	0.0%
90%	1,500	985,500	$67,366.94	$68,547.63	1.8%
90%	2,000	1,314,000	$89,239.87	$91,044.13	2.0%
90%	4,000	2,628,000	$176,702.52	$181,001.16	2.4%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 85, Primary, 3 phase service.
Bill Comparison assumes 60% on-peak, 40% off-peak energy consumption

Load Factor	kW	kWh	Net Monthly Bill Current Prices	Net Monthly Bill Proposed Prices	Percent Difference
30%	200	43,800	$3,953.63	$4,321.24	9.3%
30%	300	65,700	$5,792.42	$6,178.00	6.7%
30%	500	109,500	$9,470.02	$9,891.53	4.5%
30%	700	153,300	$13,147.62	$13,605.06	3.5%
30%	800	175,200	$14,986.41	$15,461.79	3.2%
30%	900	197,100	$16,825.22	$17,318.59	2.9%
30%	1,000	219,000	$18,664.00	$19,175.33	2.7%
30%	1,500	328,500	$27,374.10	$28,459.16	4.0%
30%	2,000	438,000	$36,155.45	$37,742.96	4.4%
30%	4,000	876,000	$69,434.11	$72,698.56	4.7%
50%	200	73,000	$5,773.62	$6,126.72	6.1%
50%	300	109,500	$8,522.42	$8,886.25	4.3%
50%	500	182,500	$14,020.01	$14,405.27	2.7%
50%	700	255,500	$19,517.59	$19,924.29	2.1%
50%	800	292,000	$22,266.39	$22,683.79	1.9%
50%	900	328,500	$25,015.17	$25,443.32	1.7%
50%	1,000	365,000	$27,763.96	$28,202.82	1.6%
50%	1,500	547,500	$40,579.92	$42,000.38	3.5%
50%	2,000	730,000	$53,763.21	$55,797.93	3.8%
50%	4,000	1,460,000	$103,188.45	$107,125.39	3.8%
70%	200	102,200	$7,593.61	$7,932.22	4.5%
70%	300	153,300	$11,252.42	$11,594.50	3.0%
70%	500	255,500	$18,569.99	$18,919.01	1.9%
70%	700	357,700	$25,887.57	$26,243.52	1.4%
70%	800	408,800	$29,546.36	$29,905.80	1.2%
70%	900	459,900	$33,205.16	$33,568.04	1.1%
70%	1,000	511,000	$36,863.93	$37,230.30	1.0%
70%	1,500	766,500	$52,169.80	$53,634.40	2.8%
70%	2,000	1,022,000	$69,205.39	$71,298.97	3.0%
70%	4,000	2,044,000	$136,880.79	$141,490.23	3.4%
90%	200	131,400	$9,413.62	$9,737.73	3.4%
90%	300	197,100	$13,982.42	$14,302.75	2.3%
90%	500	328,500	$23,119.97	$23,432.76	1.4%
90%	700	459,900	$32,257.56	$32,562.76	0.9%
90%	800	525,600	$36,826.33	$37,127.77	0.8%
90%	900	591,300	$41,395.14	$41,692.81	0.7%
90%	1,000	657,000	$45,963.91	$46,257.79	0.6%
90%	1,500	985,500	$64,913.92	$66,630.72	2.6%
90%	2,000	1,314,000	$86,051.56	$88,481.38	2.8%
90%	4,000	2,628,000	$170,573.13	$175,855.07	3.1%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 89, Secondary.
Bill Comparison assumes 60% on-peak, 40% off-peak energy consumption

Load Factor	kW	kWh	Net Monthly Bill: Current Prices	Net Monthly Bill: Proposed Prices	Percent Difference
30%	4,000	876,000	$72,026.57	$75,319.41	4.6%
30%	7,500	1,642,500	$128,996.63	$134,224.40	4.1%
30%	10,000	2,190,000	$169,645.24	$176,255.08	3.9%
30%	15,000	3,285,000	$250,942.46	$260,316.47	3.7%
30%	20,000	4,380,000	$332,239.68	$344,377.86	3.7%
50%	4,000	1,460,000	$106,959.89	$108,705.62	1.6%
50%	7,500	2,737,500	$194,380.35	$196,707.29	1.2%
50%	10,000	3,650,000	$256,823.53	$259,565.60	1.1%
50%	15,000	5,475,000	$381,709.90	$385,282.25	0.9%
50%	20,000	7,300,000	$506,596.27	$510,998.90	0.9%
70%	4,000	2,044,000	$141,831.21	$142,029.83	0.1%
70%	7,500	3,832,500	$259,764.07	$259,190.18	-0.2%
70%	10,000	5,110,000	$344,001.83	$342,876.12	-0.3%
70%	15,000	7,665,000	$512,477.34	$510,248.03	-0.4%
70%	20,000	10,220,000	$680,952.86	$677,619.94	-0.5%
90%	4,000	2,628,000	$176,702.52	$175,354.04	-0.8%
90%	7,500	4,927,500	$325,147.79	$321,673.07	-1.1%
90%	10,000	6,570,000	$431,180.12	$426,186.64	-1.2%
90%	15,000	9,855,000	$643,244.78	$635,213.81	-1.2%
90%	20,000	13,140,000	$855,309.44	$844,240.98	-1.3%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 89, Primary, 3 phase service.
Bill Comparison assumes 60% on-peak, 40% off-peak energy consumption

			Net Monthly Bill		
Load Factor	kW	kWh	Current Prices	Proposed Prices	Percent Difference
30%	4,000	876,000	$69,434.11	$72,752.90	4.8%
30%	7,500	1,642,500	$124,352.06	$129,763.68	4.4%
30%	10,000	2,190,000	$163,534.87	$170,441.35	4.2%
30%	15,000	3,285,000	$241,900.50	$251,796.72	4.1%
30%	20,000	4,380,000	$320,266.14	$333,152.10	4.0%
50%	4,000	1,460,000	$103,188.45	$105,080.43	1.8%
50%	7,500	2,737,500	$187,525.20	$190,261.56	1.5%
50%	10,000	3,650,000	$247,765.71	$251,105.18	1.3%
50%	15,000	5,475,000	$368,246.77	$372,792.47	1.2%
50%	20,000	7,300,000	$488,727.83	$494,479.76	1.2%
70%	4,000	2,044,000	$136,880.79	$137,345.96	0.3%
70%	7,500	3,832,500	$250,698.33	$250,759.43	0.0%
70%	10,000	5,110,000	$331,996.56	$331,769.01	-0.1%
70%	15,000	7,665,000	$494,593.04	$493,788.22	-0.2%
70%	20,000	10,220,000	$657,189.52	$655,807.42	-0.2%
90%	4,000	2,628,000	$170,573.13	$169,611.50	-0.6%
90%	7,500	4,927,500	$313,871.46	$311,257.30	-0.8%
90%	10,000	6,570,000	$416,227.41	$412,432.84	-0.9%
90%	15,000	9,855,000	$620,939.31	$614,783.97	-1.0%
90%	20,000	13,140,000	$825,651.21	$817,135.09	-1.0%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 89, Transmission
Bill Comparison assumes 60% on-peak, 40% off-peak energy consumption

Load Factor	kW	kWh	Net Monthly Bill Current Prices	Net Monthly Bill Proposed Prices	Percent Difference
30%	4,000	876,000	$65,496.04	$69,122.64	5.5%
30%	5,000	1,095,000	$80,007.18	$84,375.63	5.5%
30%	10,000	2,190,000	$152,252.87	$160,330.56	5.3%
30%	20,000	4,380,000	$296,744.23	$312,240.42	5.2%
30%	40,000	8,760,000	$585,726.97	$616,060.14	5.2%
30%	50,000	10,950,000	$730,218.33	$767,970.00	5.2%
30%	70,000	15,330,000	$1,019,201.06	$1,071,789.71	5.2%
50%	4,000	1,460,000	$98,733.08	$100,987.01	2.3%
50%	5,000	1,825,000	$121,475.97	$124,128.58	2.2%
50%	10,000	3,650,000	$235,190.44	$239,836.47	2.0%
50%	20,000	7,300,000	$462,619.39	$471,252.23	1.9%
50%	40,000	14,600,000	$917,477.28	$934,083.76	1.8%
50%	50,000	18,250,000	$1,144,906.22	$1,165,499.53	1.8%
50%	70,000	25,550,000	$1,599,764.11	$1,628,331.06	1.8%
70%	4,000	2,044,000	$131,908.11	$132,789.37	0.7%
70%	5,000	2,555,000	$162,944.76	$163,881.54	0.6%
70%	10,000	5,110,000	$318,128.02	$319,342.37	0.4%
70%	20,000	10,220,000	$628,494.54	$630,264.04	0.3%
70%	40,000	20,440,000	$1,249,227.59	$1,252,107.38	0.2%
70%	50,000	25,550,000	$1,559,594.11	$1,563,029.06	0.2%
70%	70,000	35,770,000	$2,180,327.15	$2,184,872.40	0.2%
90%	4,000	2,628,000	$165,083.13	$164,591.73	-0.3%
90%	5,000	3,285,000	$204,413.55	$203,634.49	-0.4%
90%	10,000	6,570,000	$401,065.60	$398,848.28	-0.6%
90%	20,000	13,140,000	$794,369.70	$789,275.85	-0.6%
90%	40,000	26,280,000	$1,580,977.90	$1,570,131.01	-0.7%
90%	50,000	32,850,000	$1,974,282.00	$1,960,558.59	-0.7%
90%	70,000	45,990,000	$2,760,890.19	$2,741,413.74	-0.7%

PORTLAND GENERAL ELECTRIC
RATE DESIGN INPUT
SUMMARY - ALLOCATION OF 2014 COSTS TO RATE SCHEDULES ($000)

Grouping	Power Supply	Energy-Based Charges: Franchise Fees	Trojan	Sch 129	Subtotal	Trans. & Related Charges: Transmission	Ancillary Services	Subtotal	Distribution Demand & Facilities Charges: Substation	Subtrans.	Feeder Backbone	Feeder Facilities	Subtotal
Schedule 7	$495,375	$22,778	$1,505		$24,283	$20,389	$2,201	$22,589	$25,583	$28,146	$61,252	$63,963	$178,944
Schedule 15	$1,174	$125	$4		$128	$37	$5	$42	$78	$86	$196	$138	$498
Schedule 32	$95,175	$4,490	$290		$4,780	$3,504	$423	$3,927	$4,119	$4,532	$11,453	$13,247	$33,351
Schedule 38	$1,828	$94	$5		$100	$64	$8	$72	$177	$195	$586	$546	$1,505
Schedule 47	$1,589	$154	$4		$158	$77	$7	$84	$236	$259	$1,637	$1,176	$3,308
Schedule 49	$4,931	$395	$14		$408	$238	$22	$260	$754	$829	$5,337	$2,606	$9,525
Schedule 83													
Secondary	$165,839	$6,069	$503		$6,572	$5,870	$738	$6,608	$7,293	$8,024	$17,786	$10,612	$43,715
Schedule 85													
Secondary		$3,974	$406	($4,452)	($72)								
Primary		$426	$48	($542)	($68)								
Class Total	$126,221					$4,311	$566	$4,877	$6,575	$7,234	$13,729	$5,971	$33,510
Schedule 85 1-4 MW													
Secondary		$901	$89	($1,009)	($19)								
Primary		$921	$100	($1,171)	($150)								
Class Total	$54,209					$1,757	$236	$1,993	$2,754	$3,029	$5,752	$1,570	$13,106
Schedule 89 GT 4 MW													
Secondary		$29	$3	($34)	($2)						$186		$186
Primary		$3,453	$427	($5,028)	($1,148)						$2,889		$2,889
Subtransmission		$364	$84	($1,001)	($553)						$851		$851
Class Total	$125,202					$3,780	$555	$4,335	$4,830	$6,350			$11,179
Schedules 91 & 95	$5,227	$450	$16		$466	$165	$23	$188	$349	$384	$871	$614	$2,218
Schedules 92	$231	$8	$1		$9	$7	$1	$8	$7	$8	$17	$6	$38
Schedule 93	$27	$4	$0		$4	$0	$0	$1	$13	$14	$33	$23	$83
Totals	$1,077,028	$44,634	$3,498	($13,237)	$34,896	$40,198	$4,786	$44,984	$52,768	$59,091	$122,574	$100,472	$334,905

PORTLAND GENERAL ELECTRIC
RATE DESIGN INPUTS (CONTINUED)
SUMMARY - ALLOCATION OF 2014 COSTS TO RATE SCHEDULES ($000)

	Dist. Customer-Related TSM		Uncollectibles		Metering		Billing		Other Consumer		Subtotal				Total
Grouping	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase	Fixed Costs	Subtotal	Cost Allocations
Schedule 7	$96,120	$21	$7,892	$1	$2,465	$0	$49,880	$6	$32,477	$4	$188,834	$32		$188,866	$910,058
Schedule 15	$316		$0		$0		$161		$149		$627	$0	$2,517	$3,143	$4,985
Schedule 32	$9,788	$14,794	$257	$166	$407	$263	$4,827	$3,119	$5,480	$3,541	$20,760	$21,883		$42,642	$179,875
Schedule 38	$12	$185	$0	$0	$4	$23	$2	$13	$4	$26	$22	$248		$270	$3,775
Schedule 47	$18	$407	$1	$7	$2	$21	$19	$258	$19	$252	$57	$944		$1,002	$6,140
Schedule 49	$0	$383	$0	$20	$0	$14	$0	$131	$0	$117	$1	$665		$666	$15,791
Schedule 83															
Secondary	$420	$15,975	$19	$288	$26	$394	$82	$1,221	$128	$1,922	$675	$19,799		$20,474	$243,208
Schedule 85															
Secondary		$3,204		$95		$107		$76		$2,416	$0	$5,898		$5,898	
Primary		$416		$11		$12		$9		$280	$0	$729		$729	$171,095
Schedule 85 1-4 MW															
Secondary		$484		$21		$5		$5		$624	$0	$1,138		$1,138	
Primary		$227		$21		$5		$5		$619	$0	$876		$876	$71,152
Schedule 89 GT 4 MW															
Secondary		$29		$23		$0		$0		$181	$0	$233		$233	
Primary		$155		$362		$0		$2		$2,801	$0	$3,320		$3,320	
Subtransmission		$169		$93		$0		$0		$723	$0	$985		$985	$147,477
Schedule 91	$1,697			$0		$0	$117		$150		$1,964	$0	$7,946	$9,911	$18,009
Schedules 92 & 94		$27		$0		$0		$10		$7	$0	$44		$44	$329
Schedule 93		$42		$0		$2		$2		$5	$0	$51		$51	$165
Totals	$108,372	$36,518	$8,169	$1,109	$2,903	$845	$55,088	$4,855	$38,409	$13,517	$212,941	$56,845	$10,463	$280,248	$1,772,061

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2014

Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULE 7						
Residential						
Allocations						
Functional Costs						
Basic Charge						
Single-Phase	$188,834	733,968	Customers	$21.44	per cust. per mo.	$188,835
Three-Phase	$32	82	Customers	$32.07	per cust. per mo.	$32
Trans. & Rel. Serv. Charge	$22,589	7,542,460	MWh	2.99	mills/kWh	$22,552
Distribution Charge	$178,944	7,542,460	MWh	23.72	mills/kWh	$178,907
Franchise Fees & Other	$24,283	7,542,460	MWh	3.22	mills/kWh	$24,287
Energy Charge	$495,375	7,542,460	MWh	65.68	mills/kWh	$495,389
Subtotal	$910,058					$910,001
Pricing						
Functional Costs						
Basic Charge						
Single-Phase		733,968	Customers	$10.00	per cust. per mo.	$88,076
Three-Phase		82	Customers	$10.00	per cust. per mo.	$10
Trans. & Rel. Serv. Charge		7,542,460	MWh	2.99	mills/kWh	$22,552
Distribution Charge		7,542,460	MWh	37.09	mills/kWh	$279,750
System Usage Charge Calculation						
Franchise Fees & Other		7,542,460	MWh	3.22	mills/kWh	$24,287
Cust Impact Offset		7,542,460	MWh	(0.69)	mills/kWh	($5,204)
System Usage Charge		7,542,460	MWh	2.53	mills/kWh	$19,082
Energy Charge						
Block 1 (First 500 kWh)		3,940,990	MWh	64.33	mills/kWh	$253,537
Block 2 (501-1,000 kWh)		2,196,590	MWh	64.33	mills/kWh	$141,314
Block 3 (Over 1,000 kWh)		1,404,880	MWh	71.55	mills/kWh	$100,524
Subtotal						$904,846
					w/o CIO	$910,050
SCHEDULE 15						
Outdoor Area Lighting						
Allocations						
Functional Costs						
Basic Charge	$627	2,254	Customers	$23.17	per cust. per mo.	$627
Trans. & Rel. Serv. Charge	$42	23,112	MWh	1.82	mills/kWh	$42
Distribution Charge	$498	23,112	MWh	21.55	mills/kWh	$498
Franchise Fees & Other	$128	23,112	MWh	5.55	mills/kWh	$128
Energy Charge	$1,174	23,112	MWh	50.78	mills/kWh	$1,174
Fixed Charges	$2,517	23,112	MWh			$2,517
Subtotal	$4,985					$4,985
Pricing						
Functional Costs						
Trans. & Rel. Serv. Charge		23,112	MWh	1.82	mills/kWh	$42
Distribution Charge		23,112	MWh	48.66	mills/kWh	$1,125
System Usage Charge Calc						
Franchise Fees & Other		23,112	MWh	5.55	mills/kWh	$128
Cust Impact Offset		23,112	MWh	(7.39)	mills/kWh	($171)
System Usage Charge		23,112	MWh	(1.84)	mills/kWh	($43)
Energy Charge		23,112	MWh	50.78	mills/kWh	$1,174
Fixed Charges		23,112	MWh			$2,517
Subtotal						$4,814
					w/o CIO	$4,985

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2014

Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULE 32						
General Service <30 kW						
Allocations						
Functional Costs						
Basic Charge						
Single-Phase	$20,760	53,942	Customers	$32.07	per cust. per mo.	$20,759
Three-Phase	$21,883	34,854	Customers	$52.32	per cust. per mo.	$21,883
Trans. & Rel. Serv. Charge	$3,927	1,580,824	MWh	2.48	mills/kWh	$3,920
Distribution Charge	$33,351	1,580,824	MWh	21.10	mills/kWh	$33,355
Franchise Fees & Other	$4,780	1,580,824	MWh	3.02	mills/kWh	$4,774
Energy Charge	$95,175	1,580,824	MWh	60.21	mills/kWh	$95,181
Subtotal	$179,875					$179,873
Pricing						
Functional Costs						
Basic Charge						
Single-Phase		53,942	Customers	$14.00	per cust. per mo.	$9,062
Three-Phase		34,854	Customers	$18.00	per cust. per mo.	$7,529
Trans. & Rel. Serv. Charge		1,580,824	MWh	2.48	mills/kWh	$3,920
Distribution Charge						
First 5 MWh		1,399,259	MWh	41.68	mills/kWh	$58,321
Over 5 MWh		181,564	MWh	6.00	mills/kWh	$1,089
System Usage Charge Calc						
Franchise Fees & Other		1,580,824	MWh	3.02	mills/kWh	$4,774
Cust Impact Offset		1,580,824	MWh	(0.69)	mills/kWh	($1,091)
System Usage Charge		1,580,824	MWh	2.33	mills/kWh	$3,683
Energy Charge		1,580,824	MWh	60.21	mills/kWh	$95,181
Subtotal						$178,787
					w/o CIO	$179,877
SCHEDULE 38						
Time-of-Day G.S. >30 kW						
Allocations						
Functional Costs						
Basic						
Single-Phase	$22	38	Customers	$48.84	per cust. per mo.	$22
Three-Phase	$299	262	Customers	$95.01	per cust. per mo.	$299
Trans. & Rel. Serv. Charge	$73	30,898	MWh	2.35	per cust. per mo.	$73
Distribution Charges	$1,588	30,898	MWh	51.39	per cust. per mo.	$1,588
Franchise Fees & Other	$104	30,898	MWh	3.36	mills/kWh	$104
Energy Charge	$1,854	30,898	MWh	60.02	mills/kWh	$1,854
Subtotal	$3,940					$3,940
Pricing						
Functional Costs						
Basic						
Single-Phase		38	Customers	$25.00	per cust. per mo.	$11
Three-Phase		262	Customers	$25.00	per cust. per mo.	$79
Trans. & Rel. Serv. Charge		30,898	MWh	2.35	mills/kWh	$73
Distribution Charges		30,898	MWh	58.13	mills/kWh	$1,796
System Usage Charge						
Franchise Fees & Other		30,898	MWh	3.36	mills/kWh	$104
Cust Impact Offset		30,898	MWh	1.74	mills/kWh	$54
System Usage Charge		30,898	MWh	5.10	mills/kWh	$158
Energy Charge Calc						
On-Peak (special)		16,678	MWh	64.62	mills/kWh	$1,078
Off-Peak		14,220	MWh	54.62	mills/kWh	$777
Reactive Demand Charge		46,056	kVar	$0.50	kVar	$23
Subtotal						$3,994
					w/o CIO	$3,940

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2014

Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULE 47						
Irrig. & Drain. Pump. - < 30 kW						
Allocations						
Functional Costs						
Basic Charge						
Single-Phase	$57	220	Customers	$43.51	per cust. per summ. mo.	$57
Three-Phase	$944	2,983	Customers	$52.75	per cust. per summ. mo.	$944
Trans. & Rel. Serv. Charge	$84	21,482	MWh	3.91	mills/kWh	$84
Distribution Charges	$3,308	21,482	MWh	153.97	mills/kWh	$3,308
Franchise Fees & Other	$158	21,482	MWh	7.35	mills/kWh	$158
Energy Charge	$1,589	21,482	MWh	73.99	mills/kWh	$1,589
Subtotal	$6,140					$6,140
Pricing						
Functional Costs						
Basic Charge						
Single-Phase		220	Customers	$30.00	per cust. per summ. mo.	$40
Three-Phase		2,983	Customers	$30.00	per cust. per summ. mo.	$537
Trans. & Rel. Serv. Charge		21,482	MWh	3.91	mills/kWh	$84
Distribution Charge Calc						
First 50 kWh per kW		7,847	MWh	186.45	mills/kWh	$1,463
Over 50 kWh per kW		13,635	MWh	166.45	mills/kWh	$2,270
System Usage Charge Calc						
Franchise Fees & Other		21,482	MWh	7.35	mills/kWh	$158
Cust Impact Offset		21,482	MWh	(127.82)	mills/kWh	($2,746)
System Usage Charge		21,482	MWh	(120.47)	mills/kWh	($2,588)
Energy Charge		21,482	MWh	73.99	mills/kWh	$1,589
Reactive Demand Charge		215	kVar	$0.50	kVar	$0
Subtotal with Consumer Impact Offset						$3,395
					w/o CIO	$6,141
SCHEDULE 49						
Irrig. & Drain. Pump. - > 30 kW						
Allocations						
Functional Costs						
Basic						
Single-Phase	$1	4	Customers	$54.46	per cust. per summ. mo.	$1
Three-Phase	$665	1,292	Customers	$85.80	per cust. per summ. mo.	$665
Trans. & Rel. Serv. Charge	$260	68,174	MWh	3.82	mills/kWh	$260
Distribution Charges	$9,525	68,174	MWh	139.72	mills/kWh	$9,525
Franchise Fees & Other	$408	68,174	MWh	5.99	mills/kWh	$408
Energy Charge	$4,931	68,174	MWh	72.33	mills/kWh	$4,931
Subtotal	$15,791					$15,792
Pricing						
Functional Costs						
Basic Charge						
Single-Phase		4	Customers	$35.00	per cust. per summ. mo.	$1
Three-Phase		1,292	Customers	$35.00	per cust. per summ. mo.	$271
Trans. & Rel. Serv. Charge		68,174	MWh	3.82	mills/kWh	$260
Distribution Charge Calc						
First 50 kWh per kW		21,413	MWh	159.15	mills/kWh	$3,408
Over 50 kWh per kW		46,761	MWh	139.15	mills/kWh	$6,507
System Usage Charge Calc						
Franchise Fees & Other		68,174	MWh	5.99	mills/kWh	$408
Cust Impact Offset		68,174	MWh	(120.71)	mills/kWh	($8,229)
System Usage Charge		68,174	MWh	(114.72)	mills/kWh	($7,821)
Energy Charge		68,174	MWh	72.33	mills/kWh	$4,931
Reactive Demand Charge		10,578	kVar	$0.50	kVar	$5
Subtotal with Consumer Impact Offset						$7,563
					w/o CIO	$15,792

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2014

Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULE 83						
General Service 31-200 kW						
Allocations						
Functional Costs						
Basic Charge						
Single-Phase Secondary	$675	697	Customers	$80.75	per cust, per mo.	$675
Three-Phase Secondary	$19,799	10,433	Customers	$158.15	per cust, per mo.	$19,799
Transmission & Related Service Charge	$6,608	8,424,004	kW demand	$0.78	per kW demand	$6,571
Distribution Charges						
Feeder Backbone	$17,786	10,622,177	kW faccap	$1.67	per kW faccap	$17,739
Feeder Local Facilities	$10,612	10,622,177	kW faccap	$1.00	per kW faccap	$10,622
Subtransmission Charge	$8,024	8,424,004	kW demand	$0.95	per kW demand	$8,003
Substation Charge	$7,293	8,424,004	kW demand	$0.87	per kW demand	$7,329
Secondary Franchise Fees & Other	$6,572	2,796,682	MWh	2.35	mills/kWh	$6,572
Secondary COS Energy Charge	$165,839	2,796,682	MWh	59.30	mills/kWh	$165,843
Subtotal	$243,208					$243,153
Pricing						
Functional Costs						
Basic Charge						
Secondary Single-Phase		697	Customers	$30.00	per cust, per mo.	$251
Secondary Three-Phase		10,433	Customers	$40.00	per cust, per mo.	$5,008
Trans. & Rel. Serv. Charge						
On-peak		8,405,722	kW demand	$0.88	per kW demand	$7,397
Off-peak		18,282	kW demand	$0.00	per kW demand	$0
Distribution Charges						
Secondary Facilities Charge						
First 30 kW		4,006,530	kW faccap	$2.98	<= 30 kW faccap	$11,939.459
Over 30 kW		6,615,647	kW faccap	$2.48	> 30 kW faccap	$16,406.805
Secondary Demand Charge						
On-peak		8,405,722	kW demand	$2.05	per kW demand	$17,232
Off-peak		18,282	kW demand	$0.00	per kW demand	$0
Secondary System Usage Charge Calc						
Franchise Fees & Other		2,796,682	MWh	2.35	mills/kWh	$6,572
Cust Impact Offset		2,796,682	MWh	1.74	mills/kWh	$4,866
Rate Design		2,796,682	MWh	4.40	mills/kWh	$12,305
System Usage Charge		2,796,682	MWh	8.49	mills/kWh	$23,744
COS Energy Charge						
On-peak		1,807,073	MWh	61.78	mills/kWh	$111,641
Off-peak		989,609	MWh	54.78	mills/kWh	$54,211
Reactive Demand Charge		513,800	kVar	$0.50	kVar	$257
Subtotal						$248,086
					w/o CIO	$243,220

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2014

Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULE 85						
General Service 201-4,000 kW						
Allocations						
Functional Costs						
Basic Charge						
Secondary	$7,036	1,415	Customers	$414.23	per cust, per mo.	$7,036
Primary	$1,605	234	Customers	$570.90	per cust, per mo.	$1,605
Transmission & Related Service Charge	$6,869	8,157,446	kW on-peak	$0.84	per kW demand	$6,852
Distribution Charges						
Feeder Backbone	$19,481	11,210,430	kW faccap	$1.74	per kW faccap	$19,506
Feeder Local Facilities	$7,542	11,210,430	kW faccap	$0.67	per kW faccap	$7,511
Subtransmission Charge	$10,264	9,469,916	kW on-peak	$1.08	per kW on-peak demand	$10,228
Substation Charge	$9,329	9,469,916	kW on-peak	$0.99	per kW on-peak demand	$9,375
Secondary Franchise Fees & Other	($91)	2,913,584	MWh	(0.03)	mills/kWh	($87)
Primary Franchise Fees & Other	($218)	914,107	MWh	(0.24)	mills/kWh	($219)
COS Energy Charge	$180,429	3,165,188	MWh	57.00	mills/kWh	$180,416
Subtotal	$242,246					$242,222
Pricing						
Functional Costs						
Basic Charge						
Secondary		1,415	Customers	$370	per cust, per mo.	$6,284
Primary		234	Customers	$390	per cust, per mo.	$1,096
Secondary Trans. & Rel. Serv. Charge		6,499,505	kW on-peak	$0.88	per kW demand	$5,720
Primary Trans. & Rel. Serv. Charge		1,657,941	kW on-peak	$0.85	per kW demand	$1,409
Distribution Charges						
Secondary Facilities Charge						
First 200 kW		3,397,000	kW faccap	$3.12	per kW faccap	$10,599
Over 200 kW		5,343,229	kW faccap	$2.12	per kW faccap	$11,328
Primary Facilities Charge						
First 200 kW		562,200	kW faccap	$3.04	per kW faccap	$1,709
Over 200 kW		1,908,001	kW faccap	$2.04	per kW faccap	$3,892
Secondary Demand Charge		7,359,380	kW on-peak	$2.05	per kW demand	$15,087
Primary Demand Charge		2,110,536	kW on-peak	$1.99	per kW demand	$4,200
Secondary System Usage Charge Calc						
COS Franchise Fees & Other		2,478,641	MWh	0.20	mills/kWh	$496
Cust Impact Offset		2,478,641	MWh	1.74	mills/kWh	$4,313
COS System Usage Charge		2,478,641	MWh	1.94	mills/kWh	$4,809
DA Franchise Fees & Other		434,943	MWh	(1.32)	mills/kWh	($574)
Cust Impact Offset		434,943	MWh	1.74	mills/kWh	$757
DA System Usage Charge		434,943	MWh	0.42	mills/kWh	$183
Primary System Usage Charge Calc						
COS Franchise Fees & Other		686,547	MWh	0.13	mills/kWh	$89
Cust Impact Offset		686,547	MWh	1.74	mills/kWh	$1,195
COS System Usage Charge		686,547	MWh	1.87	mills/kWh	$1,284
DA Franchise Fees & Other		227,560	MWh	(1.34)	mills/kWh	($305)
Cust Impact Offset		227,560	MWh	1.74	mills/kWh	$396
DA System Usage Charge		227,560	MWh	0.40	mills/kWh	$91
Secondary COS Energy Charge						
On-peak		1,625,951	MWh	60.85	mills/kWh	$98,939
Off-peak		852,690	MWh	50.85	mills/kWh	$43,359
Primary COS Energy Charge						
On-peak		430,280	MWh	59.28	mills/kWh	$25,507
Off-peak		256,267	MWh	49.28	mills/kWh	$12,629
Reactive Demand Charge		1,635,538	kVar	$0.50	kVar	$818
Subtotal						$248,942
					w/o CIO	$242,282

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2014

Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULE 89 GT 4,000 kW						
General Service						
Allocations						
Functional Costs						
Secondary Basic Charge	$233	2	Customers	$9,698.25	per cust, per mo.	$233
Primary Basic Charge	$3,320	31	Customers	$8,924.55	per cust, per mo.	$3,320
Subtransmission Basic Charge	$985	8	Customers	$10,264.93	per cust, per mo.	$985
Transmission & Related Service Charge	$4,335	3,941,686	kW on-peak	$1.10	per kW on-peak demand	$4,336
Distribution Charges						
Feeder Backbone	$3,926	5,785,650	kW faccap	$0.68	per kW faccap	$3,934
Feeder Local Facilities						$0
Subtransmission Demand Charge	$6,350	5,305,425	kW on-peak	$1.20	per kW on-peak demand	$6,367
Substation Demand Charge	$4,830	4,330,041	kW on-peak	$1.12	per kW on-peak demand	$4,850
Secondary Franchise Fees & Other	($2)	18,273	MWh	(0.12)	mills/kWh	($2)
Primary Franchise Fees & Other	($1,148)	2,683,051	MWh	(0.43)	mills/kWh	($1,154)
Subtransmission Franchise Fees & Other	($553)	533,858	MWh	(1.04)	mills/kWh	($555)
Energy Charge	$125,202	2,414,106	MWh	51.86	mills/kWh	$125,196
Subtotal	$147,477					$147,509
Pricing						
Functional Costs						
Secondary Basic Charge		2	Customers	$4,850.00	per cust, per mo.	$116
Primary Basic Charge		31	Customers	$4,460.00	per cust, per mo.	$1,659
Subtransmission Basic Charge		8	Customers	$5,130.00	per cust, per mo.	$492
Secondary Trans. & Rel. Serv. Charge		62,056	kW on-peak	$0.88	per kW on-peak demand	$55
Primary Trans. & Rel. Serv. Charge		3,457,442	kW on-peak	$0.85	per kW on-peak demand	$2,939
Subtransmission Trans. & Rel. Serv. Charge		422,188	kW on-peak	$0.84	per kW on-peak demand	$355
Distribution Charges						
Secondary Facilities Charge						
First 1,000 kW		24,000	kW faccap	$1.90	per kW faccap	$46
1,001-4,000 kW		72,000	kW faccap	$1.90	per kW faccap	$137
Greater than 4,000 kW		16,440	kW faccap	$1.26	per kW faccap	$21
Primary Facilities Charge						
First 1,000 kW		384,000	kW faccap	$1.85	per kW faccap	$710
1,001-4,000 kW		1,152,000	kW faccap	$1.85	per kW faccap	$2,131
Greater than 4,000 kW		3,119,417	kW faccap	$1.21	per kW faccap	$3,774
Subtransmission Facilities Charge						
First 1,000 kW		96,000	kW faccap	$1.85	per kW faccap	$178
1,001-4,000 kW		288,000	kW faccap	$1.85	per kW faccap	$533
Greater than 4,000 kW		633,793	kW faccap	$1.21	per kW faccap	$767
Secondary Demand Charge		62,056	kW on-peak	$2.05	per kW on-peak demand	$127
Primary Demand Charge		4,267,985	kW on-peak	$1.99	per kW on-peak demand	$8,493
Subtransmission Demand Charge		975,384	kW on-peak	$1.12	per kW on-peak demand	$1,093
Secondary System Usage Charge Calc						
COS Franchise Fees & Other		18,273	MWh	(0.12)	mills/kWh	($2)
Cust Impact Offset		18,273	MWh	1.74	mills/kWh	$32
COS System Usage Charge		18,273	MWh	1.62	mills/kWh	$30
DA Franchise Fees & Other		0	MWh	(1.54)	mills/kWh	$0
Cust Impact Offset		0	MWh	1.74	mills/kWh	$0
DA System Usage Charge		0	MWh	0.20	mills/kWh	$0
Primary System Usage Charge Calc						
COS Franchise Fees & Other		2,191,332	MWh	(0.17)	mills/kWh	($373)
Cust Impact Offset		2,191,332	MWh	1.74	mills/kWh	$3,813
COS System Usage Charge		2,191,332	MWh	1.57	mills/kWh	$3,440
DA Franchise Fees & Other		491,720	MWh	(1.55)	mills/kWh	($762)
Cust Impact Offset		491,720	MWh	1.74	mills/kWh	$856
DA System Usage Charge		491,720	MWh	0.19	mills/kWh	$93
Subtransmission System Usage Charge Calc						
COS Franchise Fees & Other		204,501	MWh	(0.20)	mills/kWh	($41)
Cust Impact Offset		204,501	MWh	1.74	mills/kWh	$356
COS System Usage Charge		204,501	MWh	1.54	mills/kWh	$315
DA Franchise Fees & Other		329,357	MWh	(1.56)	mills/kWh	($514)
Cust Impact Offset		329,357	MWh	1.74	mills/kWh	$573
DA System Usage Charge		329,357	MWh	0.18	mills/kWh	$59
Secondary Energy Charge						
On-peak		11,096	MWh	57.81	mills/kWh	$641
Off-peak		7,177	MWh	47.81	mills/kWh	$343
Primary Energy Charge						
On-peak		1,269,889	MWh	56.11	mills/kWh	$71,253
Off-peak		921,442	MWh	46.11	mills/kWh	$42,488
Subtransmission Energy Charge						
On-peak		118,841	MWh	55.37	mills/kWh	$6,580
Off-peak		85,660	MWh	45.37	mills/kWh	$3,886
Reactive Demand Charge		698,748	kVar	$0.50	kVar	$349
Subtotal						$153,105
					w/o CIO	$147,476

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2014

Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULES 91 & 95						
Street & Highway Lighting						
Allocations						
Functional Costs						
Basic Charge	$1,964	205	Customers	$798.52	per cust, per mo.	$1,964
Trans. & Rel. Serv. Charge	$188	102,931	MWh	1.82	mills/kWh	$187
Distribution Charge	$2,218	102,931	MWh	21.55	mills/kWh	$2,218
Franchise Fees & Other	$466	102,931	MWh	4.53	mills/kWh	$466
COS Energy Charge	$5,227	102,931	MWh	50.78	mills/kWh	$5,227
Fixed Charges	$7,946					$7,946
Subtotal	$18,009					$18,009
Pricing						
Functional Costs						
Trans. & Rel. Serv. Charge		102,931	MWh	1.82	mills/kWh	$187
Distribution Charge		102,931	MWh	40.63	mills/kWh	$4,182
System Usage Charge Calc						
Franchise Fees & Other		102,931	MWh	4.53	mills/kWh	$466
Cust Impact Offset		102,931	MWh	1.66	mills/kWh	$171
System Usage Charge		102,931	MWh	6.19	mills/kWh	$637
COS Energy Charge		102,931	MWh	50.78	mills/kWh	$5,227
Fixed Charges		102,931	MWh			$7,946
Subtotal						$18,180
					w/o CIO	$18,009
SCHEDULE 92						
Traffic Signals						
Allocations						
Functional Costs						
Basic Charge	$44	17	Customers	$215.98	per cust, per mo.	$44
Trans. & Rel. Serv. Charge	$8	4,439	MWh	1.71	mills/kWh	$8
Distribution Charge	$38	4,439	MWh	8.47	mills/kWh	$38
Franchise Fees & Other	$9	4,439	MWh	2.01	mills/kWh	$9
COS Energy Charge	$231	4,439	MWh	52.04	mills/kWh	$231
Subtotal	$329					$329
Pricing						
Functional Costs						
Trans. & Rel. Serv. Charge		4,439	MWh	1.71	mills/kWh	$8
Distribution Charge		4,439	MWh	18.40	mills/kWh	$82
System Usage Charge Calc						
Franchise Fees & Other		4,439	MWh	2.01	mills/kWh	$9
Cust Impact Offset		4,439	MWh	1.74	mills/kWh	$8
System Usage Charge		4,439	MWh	3.75	mills/kWh	$17
COS Energy Charge		4,439	MWh	52.04	mills/kWh	$231
Subtotal						$337

PORTLAND GENERAL ELECTRIC
CONSUMER IMPACT OFFSET

Grouping	Cycle MWH	Revenues at 2013 Prices ($000)	2014 Allocated Costs ($000)	Percent Change	Maximum Change	Impact Offset Cap	Cap Impact Offset MWH	Spread Offset Net Cap	CIO mills/kWh	CIO Revenues
Schedule 7	7,542,460	$833,489	$911,114	9.3%	17.0%	($5,191)	(7,542,460)		(0.69)	($5,204)
Schedule 15	23,112	$4,165	$4,988	19.8%	17.0%		0		(7.39)	($171)
Schedule 32	1,580,824	$161,911	$180,081	11.2%	17.0%	($1,088)	(1,580,824)		(0.69)	($1,091)
Schedule 38	30,898	$3,714	$3,944	6.2%	17.0%	$0	0	$54	1.74	$54
Schedule 47	21,482	$2,904	$6,144	111.5%	17.0%	($2,746)	(21,482)		(127.82)	($2,746)
Schedule 49	68,174	$6,472	$15,802	144.2%	17.0%	($8,230)	(68,174)		(120.71)	($8,229)
Schedule 83	2,796,682	$233,791	$243,544	4.2%	17.0%	$0	0	$4,877	1.74	$4,866
Schedule 85	3,165,188	$255,205	$250,157	-2.0%	17.0%	$0	0	$5,519	1.74	$5,507
Schedule 89	2,414,106	$163,337	$153,448.63	-6.1%	17.0%	$0	0	$4,210	1.74	$4,201
Schedules 91 & 95	102,931	$17,468	$18,021	3.2%	17.0%		0		1.66	$171
Schedule 92	4,439	$338	$330	-2.4%	17.0%	$0	0	$8	1.74	$8
COS TOTALS	17,750,295									
Sch 485 Energy	662,503							$1,155	1.74	$1,153
Sch 76/489	821,076							$1,432	1.74	$1,429
Totals	19,233,875	$1,682,794	$1,787,572	6.2%		($17,254)	(9,212,939)	$17,254		($53)
Cap on Rate Change	17.0%									

PORTLAND GENERAL ELECTRIC
2014 Test Period Functionalized Revenue Requirement

Function	Amount	Spread
PRODUCTION	$1,077,604	$1,077,604
TRANSMISSION	$40,218	$40,218
ANCILLARY	$4,788	$4,788
DISTRIBUTION	$546,993	$546,993
METERING	$3,750	$3,750
BILLING	$59,971	$59,971
CONSUMER	$51,950	$51,950
TOTALS	$1,785,274	$1,785,274
Schedule 129		($13,239)
Employee Discount		$928
Spread Total		$1,772,963

Note: Employee discount is allocated to distribution
Note: Schedule 129 Long-Term Transition Adjustment is allocated to Schedules 85 and 89

PORTLAND GENERAL ELECTRIC
UNBUNDLED 2014 COSTS ($000)

	Unbundled Costs	Adjusted to Cycle
Fixed Generation Revenue Requirement	$438,410	$438,175
Net Variable Power Costs	$639,194	$638,852
Production Costs	$1,077,604	$1,077,028
Ancillary Services	$4,788	$4,786
Transmission	$40,218	$40,198
Distribution Services	$546,993	
Franchise	($44,653)	
Uncollectibles	($9,283)	
Trojan Decommissioning	($3,500)	
Employee Discount	$928	$928
Distribution Costs	$490,485	$490,257
Consumer Services		
Metering Services	$3,750	$3,748
Billing Services	$59,971	$59,943
Other Consumer Services	$51,950	$51,926
Franchise Fees	$44,653	$44,632
Uncollectibles	$9,283	$9,279
Trojan Decommissioning	$3,500	$3,498
Schedule 129	($13,239)	($13,237)
Totals	$1,772,963	$1,772,059
Net of employee discount	$1,772,035	$1,771,131
Net of Sch 129	$1,785,274	$1,784,368
Calendar MWH	19,242,798	
Cycle MWH	19,233,875	
Cycle/Cal Ratio	99.95%	
COS Calendar Energy MWH	17,758,953	
COS Cycle MWH	17,750,295	
Cycle/Cal Ratio	99.95%	

PORTLAND GENERAL ELECTRIC
ALLOCATION OF PRODUCTION COSTS TO COS CUSTOMERS
2014

Schedules	COS Calendar Energy	Marginal Energy Costs ($000)	Generation Capacity Allocation	Marginal Capacity Costs ($000)	Marginal Capacity & Energy Costs ($000)	Capacity & Energy Allocation Percent	Allocated Capacity & Energy Costs ($000)	Cycle Basis Costs ($000)
Schedule 7	7,544,318	$398,809	50.72%	$252,556	$651,365	45.98%	$495,497	$495,375
Schedule 15	23,112	$1,085	0.09%	$458	$1,543	0.11%	$1,174	$1,174
Schedule 32	1,583,045	$81,886	8.72%	$43,404	$125,290	8.84%	$95,309	$95,175
Schedule 38	30,311	$1,610	0.16%	$791	$2,401	0.17%	$1,827	$1,828
Schedule 47	21,368	$1,126	0.19%	$952	$2,078	0.15%	$1,581	$1,589
Schedule 49	68,293	$3,544	0.59%	$2,950	$6,494	0.46%	$4,940	$4,931
Schedule 83	2,803,014	$145,786	14.60%	$72,714	$218,500	15.42%	$166,215	$165,839
Schedule 85	2,216,535	$114,100	10.72%	$53,397	$167,497	11.82%	$127,416	$126,221
Schedule 85 1-4 MW	949,580	$48,037	4.37%	$21,763	$69,800	4.93%	$53,097	$54,209
Schedule 89 GT 4 MW	2,411,439	$117,581	9.40%	$46,823	$164,404	11.61%	$125,063	$125,202
Schedule 91/95	102,931	$4,833	0.41%	$2,038	$6,871	0.49%	$5,227	$5,227
Schedule 92	4,439	$222	0.02%	$81	$304	0.02%	$231	$231
Schedule 93	569	$29	0.00%	$6	$35	0.00%	$27	$27
TOTAL	17,758,953	$918,649	100.0%	$497,933	$1,416,583	100.00%	$1,077,604	$1,077,028
Simple Cycle Proxy Plant $/kW				$140.89		TARGET	$1,077,604	
Projected Peak Load				3,534				
Marginal Capacity Costs ($000)				$497,933				

PORTLAND GENERAL ELECTRIC
Marginal Energy Costs: 2014 Test Period

Schedules	Marginal Energy Cost	Percent
Schedule 7	$398,808,672	43.41%
Schedule 15	$1,085,126	0.12%
Schedule 32	$81,886,302	8.91%
Schedule 38	$1,610,351	0.18%
Schedule 47	$1,126,022	0.12%
Schedule 49	$3,543,605	0.39%
Schedule 83	$145,785,900	15.87%
Schedule 85	$114,100,025	12.42%
Schedule 85 1-4 MW	$48,037,390	5.23%
Schedule 89 GT 4 MW	$117,581,291	12.80%
Schedule 91/95	$4,832,703	0.53%
Schedule 92	$222,413	0.02%
Schedule 93	$29,437	0.00%
TOTAL	$918,649,238	100.00%

PORTLAND GENERAL ELECTRIC
ALLOCATION OF TRANSMISSION REVENUE REQUIREMENT
2014

Schedules	Transmission Allocation Percent	Class Revenue Requirement
Schedule 7	50.72%	$20,389
Schedule 15	0.09%	$37
Schedule 32	8.72%	$3,504
Schedule 38	0.16%	$64
Schedule 47	0.19%	$77
Schedule 49	0.59%	$238
Schedule 83	14.60%	$5,870
Schedule 85	10.72%	$4,311
Schedule 85 1-4 MW	4.37%	$1,757
Schedule 89 GT 4 MW	9.40%	$3,780
Schedules 91/95	0.41%	$165
Schedule 92	0.02%	$7
Schedule 93	0.00%	$0
Target	100.00%	$40,198

PORTLAND GENERAL ELECTRIC
ALLOCATION OF ANCILLARY SERVICE COSTS
2014

Schedules	Production Allocation Percent	Class Revenue Requirement
Schedule 7	45.98%	$2,201
Schedule 15	0.11%	$5
Schedule 32	8.84%	$423
Schedule 38	0.17%	$8
Schedule 47	0.15%	$7
Schedule 49	0.46%	$22
Schedule 83	15.42%	$738
Schedule 85	11.82%	$566
Schedule 85 1-4 MW	4.93%	$236
Schedule 89 GT 4 MW	11.61%	$555
Schedules 91/95	0.49%	$23
Schedule 92	0.02%	$1
Schedule 93	0.00%	$0
TOTAL	100.00%	$4,786
	TARGET	$4,786

PORTLAND GENERAL ELECTRIC
Applicable 2014 Ancillary Services Charges

Line	Ancillary Service	Billing Determinant	OATT Price	Total
	SCHEDULE 1 - SCHEDULING, SYSTEM CONTROL and DISPATCH		$/MW year	
1	12 CP MW Average	2,893	$149.89	$433,603
	SCHEDULE 2 - REACTIVE SUPPLY & VOLTAGE CONTROL		$/kW year	
2	12 CP kW Average	2,892,808	$0.461	$1,333,585
	SCHEDULE 3 - REGULATION & FREQUENCY RESPONSE		$/kW month	
3	Billing Determinant: Sum of Monthly Average 12 CP KW	34,713,700	$0.09	$3,021,307
	Charge: $6.695 per kW per month x .013			
4		**ANCILLARY SERVICES TOTAL**		$4,788,495

PORTLAND GENERAL ELECTRIC
ALLOCATION OF TROJAN DECOMMISSIONING COSTS
2014

Schedules	Cycle Generation Revenues	Allocation Percent	Class Revenue Requirement
Schedule 7	$521,371,138	43.01%	$1,505
Schedule 15	$1,260,066	0.10%	$4
Schedule 32	$100,477,156	8.29%	$290
Schedule 38	$1,837,235	0.15%	$5
Schedule 47	$1,483,765	0.12%	$4
Schedule 49	$4,699,914	0.39%	$14
Schedule 83	$174,233,310	14.37%	$503
Schedule 85-S	$140,504,249	11.59%	$406
Schedule 85-S 1-4 MW	$30,938,458	2.55%	$89
Schedule 89-S GT 4 MW	$1,045,534	0.09%	$3
Schedule 85-P	$16,521,162	1.36%	$48
Schedule 85-P 1-4 MW	$34,688,588	2.86%	$100
Schedule 89-P GT 4 MW	$148,111,232	12.22%	$427
Schedule 89-T	$29,024,900	2.39%	$84
Schedule 91/95	$5,611,813	0.46%	$16
Schedule 92	$245,281	0.02%	$1
Schedule 93	$30,524	0.00%	$0
TOTAL	$1,212,084,323		$3,498
		TARGET	$3,498

PORTLAND GENERAL ELECTRIC
ALLOCATION OF FRANCHISE FEES
2014

Schedules	Distribution Allocations	Transmission Allocations	Generation Allocations	Subtotal Allocations	Distribution Fran. Fee Allocations	Transmission Fran. Fee Allocations	Generation Fran. Fee Allocations	Total Fran. Fee Allocations
Schedule 7	$369,315	$22,589	$495,375	$887,280	$9,470	$579	$12,702	$22,751
Schedule 15	$3,645	$42	$1,174	$4,861	$93	$1	$30	$125
Schedule 32	$76,283	$3,927	$95,175	$175,386	$1,956	$101	$2,440	$4,497
Schedule 38	$1,781	$72	$1,828	$3,680	$46	$2	$47	$94
Schedule 47	$4,313	$84	$1,589	$5,987	$111	$2	$41	$154
Schedule 49	$10,205	$260	$4,931	$15,397	$262	$7	$126	$395
Schedule 83-S	$64,692	$6,608	$165,839	$237,140	$1,659	$169	$4,252	$6,080
Schedule 85 201-4,000 kW	$55,899	$6,869	$180,429	$243,198	$1,433	$176	$4,626	$6,236
Schedule 89 GT 4 MW	$20,157	$4,335	$125,202	$149,694	$517	$111	$3,210	$3,838
Schedules 91/95	$12,145	$188	$5,227	$17,559	$311	$5	$134	$450
Schedule 92	$82	$8	$231	$321	$2	$0	$6	$8
Schedule 93	$134	$1	$27	$161	$3	$0	$1	$4
TOTALS	$618,652	$44,984	$1,077,028	$1,740,663	$15,863	$1,153	$27,616	$44,632

Franchise Fee Revenue Requirement **$44,632**

Schedules	Distribution MWh	Distribution mills/kWh	Transmission MWh	Transmission mills/kWh	Generation MWh	Generation mills/kWh	Total COS mills/kWh	Total DA mills/kWh
Schedule 7	7,542,460	1.26	7,542,460	0.08	7,542,460	1.68	3.02	
Schedule 15	23,112	4.04	23,112	0.05	23,112	1.30	5.39	4.04
Schedule 32	1,580,824	1.24	1,580,824	0.06	1,580,824	1.54	2.84	1.24
Schedule 38	30,329	1.51	30,329	0.06	30,329	1.55	3.11	1.51
Schedule 47	21,482	5.15	21,482	0.10	21,482	1.90	7.15	
Schedule 49	68,174	3.84	68,174	0.10	68,174	1.85	5.79	3.84
Schedule 83-S	2,796,682	0.59	2,796,682	0.06	2,796,682	1.52	2.17	0.59
Schedule 85-S 201-4,000 kW	2,913,584	0.38	2,478,641	0.06	2,478,641	1.47	1.90	0.38
Schedule 89-S GT 4 MW	18,273	0.17	18,273	0.05	18,273	1.37	1.59	0.17
Schedule 85-P 201-4,000 kW	914,107	0.37	686,547	0.06	686,547	1.42	1.84	0.37
Schedule 89-P GT 4 MW	2,683,051	0.16	2,191,332	0.05	2,191,332	1.33	1.54	0.16
Schedule 89-T	533,858	0.16	204,501	0.05	204,501	1.31	1.52	0.16
Schedule 91/95	102,931	3.03	102,931	0.05	102,931	1.30	4.37	3.03
Schedule 92	4,439	0.48	4,439	0.04	4,439	1.33	1.85	0.48
Schedule 93	569	6.04	569	0.03	569	1.20	7.26	
TOTALS	19,233,875		17,750,295		17,750,295			

Revenues

Schedules	MWh	Fran. Fee mills/kWh	Fran. Fee Revenues
Schedule 7	7,542,460	3.02	$22,778
Schedule 15	23,112	5.39	$125
Schedule 32	1,580,824	2.84	$4,490
Schedule 38	30,329	3.11	$94
Schedule 47	21,482	7.15	$154
Schedule 49	68,174	5.79	$395
Schedule 83-S	2,796,682	2.17	$6,069
Schedule 85-S 201-4,000 kW	2,478,641	1.90	$4,709
Schedule 485-S 201-4,000 kW	434,943	0.38	$165
Schedule 89-S GT 4 MW	18,273	1.59	$29
Schedule 85-P 201-4,000 kW	686,547	1.84	$1,263
Schedule 485-P 201-4,000 kW	227,560	0.37	$84
Schedule 89-P GT 4 MW	2,191,332	1.54	$3,375
Schedule 489-P GT 4 MW	491,720	0.16	$79
Schedule 89-T	204,501	1.52	$311
Schedule 489-T	329,357	0.16	$53
Schedule 91/95	102,931	4.37	$450
Schedule 92	4,439	1.85	$8
Schedule 93	569	7.26	$4
TOTALS	19,233,875		$44,634

PORTLAND GENERAL ELECTRIC
ALLOCATION OF SCHEDULE 129 TRANSITION ADJUSTMENT
2014

Schedules	Cycle Energy	Percent	Allocations ($000)
Schedule 85-S	2,375,314	33.6%	($4,452)
Schedule 85-S 1-4 MW	538,271	7.6%	($1,009)
Schedule 89-S GT 4 MW	18,273	0.3%	($34)
Schedule 85-P	289,027	4.1%	($542)
Schedule 85-P 1-4 MW	625,080	8.9%	($1,171)
Schedule 89-P GT 4 MW	2,683,051	38.0%	($5,028)
Schedule 89-T	533,858	7.6%	($1,001)
TOTAL	7,062,874	100.00%	($13,237)
		TARGET	($13,237)

PORTLAND GENERAL ELECTRIC
ALLOCATION OF UNCOLLECTIBLES
2014

Grouping	Marginal Cost Allocation Percent	Class Revenue Requirement
Schedule 7		
Single Phase	85.06%	$7,892
Three Phase	0.01%	$1
Schedule 15		
Residential	0.00%	$0
Commercial	0.00%	$0
Schedule 32		
Single Phase	2.77%	$257
Three Phase	1.79%	$166
Schedule 38		
Single Phase	0.00%	$0
Three Phase	0.00%	$0
Schedule 47		
Single Phase	0.01%	$1
Three Phase	0.08%	$7
Schedule 49		
Single Phase	0.00%	$0
Three Phase	0.21%	$20
Schedule 83		
Single Phase	0.21%	$19
Three Phase	3.10%	$288
Schedule 85		
Secondary	1.02%	$95
Primary	0.12%	$11
Schedule 85 1-4 MW		
Secondary	0.23%	$21
Primary	0.23%	$21
Schedule 89 GT 4 MW		
Secondary	0.25%	$23
Primary	3.90%	$362
Subtransmission	1.01%	$93
Schedules 91/95	0.00%	$0
Schedule 92	0.00%	$0
Schedule 93	0.00%	$0
TOTAL	100.00%	$9,279
	TARGET	$9,279

PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION COST
2014

Grouping			Usages	Units & Basis	Marginal Unit Cost	Marginal Cost Revenues	Class Revenue Requirement
Schedule 7 Residential							
CUSTOMER	Meters						
		Single-Phase Customers	733,968	Customers	$20.19	$14,819	$18,878
		Three-Phase Customers	82	Customers	$55.45	$5	$6
	Service & Transformer						
		Single-Phase Customers	733,968	Customers	$82.61	$60,633	$77,242
		Three-Phase Customers	82	Customers	$147.47	$12	$15
FACILITIES	Feeder Backbone						
		Single-Phase Customers	1,984,164	kW, rateclass peak	$24.23	$48,076	$61,246
		Three-Phase Customers	222	kW, rateclass peak	$24.23	$5	$7
	Feeder Local Facilities						
		Single-Phase Customers	2,935,872	Design Demand	$17.10	$50,203	$63,955
		Three-Phase Customers	329	Design Demand	$17.10	$6	$7
DEMAND	Subtransmission		2,010,382	kW, rateclass peak	$10.99	$22,094	$28,146
	Substation		1,984,387	kW, rateclass peak	$10.12	$20,082	$25,583
SUBTOTAL						$215,935	$275,085
Schedule 15 Residential Outdoor Area Lighting							
CUSTOMER	Customer Service		9,513	Lights	$3.39	$32	$41
	Transformer		9,513	Lights	$8.66	$82	$105
FACILITIES	Feeder Backbone		1,808	kW, rateclass peak	$25.26	$46	$58
	Feeder Local Facilities		1,808	Design Demand	$17.81	$32	$41
DEMAND	Subtransmission		1,832	kW, rateclass peak	$10.99	$20	$26
	Substation		1,808	kW, rateclass peak	$10.12	$18	$23
FIXED	Luminaires & Poles						$749
SUBTOTAL						$231	$1,043
Schedule 15 Commercial Outdoor Area Lighting							
CUSTOMER	Customer Service		11,108	Lights	$3.39	$38	$48
	Transformer		11,108	Lights	$8.66	$96	$123
FACILITIES	Feeeder Backbone		4,270	kW, rateclass peak	$25.26	$108	$137
	Feeder Local Facilities		4,270	Design Demand	$17.81	$76	$97
DEMAND	Subtransmission		4,325	kW, rateclass peak	$10.99	$48	$61
	Substation		4,270	kW, rateclass peak	$10.12	$43	$55
FIXED	Luminaires & Poles						$1,768
SUBTOTAL						$408	$2,288
Schedule 15 Outdoor Area Lighting							
CUSTOMER	Customer Service						$89
	Transformer						$227
FACILITIES	Feeeder Backbone						$196
	Feeder Local Facilities						$138
DEMAND	Subtransmission						$86
	Substation						$78
FIXED	Luminaires & Poles						$2,517
SUBTOTAL							$3,331

PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION COST
2014

Grouping			Usages	Units & Basis	Marginal Unit Cost	Marginal Cost Revenues	Class Revenue Requirement
Schedule 32 Small Non-residential General Service							
CUSTOMER	Meters						
		Single-Phase Customers	53,942	Customers	$19.37	$1,045	$1,331
		Three-Phase Customers	34,854	Customers	$68.38	$2,383	$3,036
	Service & Transformer						
		Single-Phase Customers	53,942	Customers	$123.07	$6,639	$8,457
		Three-Phase Customers	34,854	Customers	$264.80	$9,229	$11,758
FACILITIES	Feeder Backbone						
		Single-Phase Customers	129,628	kW, rateclass peak	$28.14	$3,648	$4,647
		Three-Phase Customers	189,860	kW, rateclass peak	$28.14	$5,343	$6,806
	Feeder Local Facilities						
		Single-Phase Customers	269,711	Design Demand	$24.77	$6,681	$8,511
		Three-Phase Customers	393,855	Design Demand	$9.44	$3,718	$4,736
DEMAND	Subtransmission		323,673	kW, rateclass peak	$10.99	$3,557	$4,532
	Substation		319,488	kW, rateclass peak	$10.12	$3,233	$4,119
SUBTOTAL						$45,476	$57,933
Schedule 38 General Service							
CUSTOMER	Meters						
		Single-Phase Customers	38	Customers	$57.76	$2	$3
		Three-Phase Customers	238	Customers	$82.42	$20	$25
	Service & Transformer						
		Single-Phase Customers	38	Customers	$195.06	$7	$9
		Three-Phase Customers	238	Customers	$527.62	$126	$160
FACILITIES	Feeder Backbone						
		Single-Phase Customers	858	kW, rateclass peak	$33.47	$29	$37
		Three-Phase Customers	12,894	kW, rateclass peak	$33.47	$432	$550
	Feeder Local Facilities						
		Single-Phase Customers	1,699	Design Demand	$20.26	$34	$44
		Three-Phase Customers	30,128	Design Demand	$13.09	$394	$502
DEMAND	Subtransmission		13,933	kW, rateclass peak	$10.99	$153	$195
	Substation		13,752	kW, rateclass peak	$10.12	$139	$177
SUBTOTAL						$1,336	$1,702
Schedule 47 Irrigation & Drainage Service - < 30 kW							
CUSTOMER	Meters						
		Single-Phase Customers	220	Customers	$53.83	$12	$15
		Three-Phase Customers	2,983	Customers	$81.81	$244	$311
	Service & Transformer						
		Single-Phase Customers	220	Customers	$9.70	$2	$3
		Three-Phase Customers	2,983	Customers	$25.26	$75	$96
FACILITIES	Feeder Backbone						
		Single-Phase Customers	724	kW, rateclass peak	$70.23	$51	$65
		Three-Phase Customers	17,569	kW, rateclass peak	$70.23	$1,234	$1,572
	Feeder Local Facilities						
		Single-Phase Customers	2,200	Design Demand	$52.32	$115	$147
		Three-Phase Customers	29,830	Design Demand	$27.08	$808	$1,029
DEMAND	Subtransmission		18,533	kW, rateclass peak	$10.99	$204	$259
	Substation		18,293	kW, rateclass peak	$10.12	$185	$236
SUBTOTAL						$2,930	$3,732

PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION COST
2014

Grouping			Usages	Units & Basis	Marginal Unit Cost	Marginal Cost Revenues	Class Revenue Requirement
Schedule 49 Irrigation & Drainage Service - > 30 kW							
CUSTOMER	Meters						
		Single-Phase Customers	4	Customers	$57.76	$0	$0
		Three-Phase Customers	1,292	Customers	$99.76	$129	$164
	Service & Transformer						
		Single-Phase Customers	4	Customers	$27.36	$0	$0
		Three-Phase Customers	1,292	Customers	$132.97	$172	$219
FACILITIES	Feeder Backbone						
		Single-Phase Customers	92	kW, rateclass peak	$71.65	$7	$8
		Three-Phase Customers	58,374	kW, rateclass peak	$71.65	$4,183	$5,328
	Feeder Local Facilities						
		Single-Phase Customers	124	Design Demand	$44.06	$5	$7
		Three-Phase Customers	74,290	Design Demand	$27.46	$2,040	$2,599
DEMAND	Subtransmission		59,231	kW, rateclass peak	$10.99	$651	$829
	Substation		58,466	kW, rateclass peak	$10.12	$592	$754
SUBTOTAL						$7,778	$9,909
Schedule 83 General Service (31-200 kW)							
CUSTOMER	Meters						
		Single-Phase Customers	697	Customers	$46.44	$32	$41
		Three-Phase Customers	10,433	Customers	$108.37	$1,131	$1,440
	Service & Transformer						
		Single-Phase Customers	697	Customers	$426.41	$297	$378
		Three-Phase Customers	10,433	Customers	$1,093.60	$11,409	$14,534
FACILITIES	Feeder Backbone						
		Single-Phase Customers	20,146	kW, rateclass peak	$24.68	$497	$633
		Three-Phase Customers	545,554	kW, rateclass peak	$24.68	$13,464	$17,152
	Feeder Local Facilities						
		Single-Phase Customers	31,489	Design Demand	$20.63	$650	$828
		Three-Phase Customers	853,385	Design Demand	$9.00	$7,680	$9,784
DEMAND	Subtransmission		573,111	kW, rateclass peak	$10.99	$6,298	$8,024
	Substation		565,700	kW, rateclass peak	$10.12	$5,725	$7,293
SUBTOTAL						$47,184	$60,109
Schedule 85 General Service (201-1,000 kW)							
CUSTOMER	Meters						
		Secondary Customers	1,335	Customers	$151.34	$202	$257
		Primary Customers	155	Customers	$1,382.27	$214	$273
	Service & Transformer						
		Secondary Customers	1,335	Customers	$1,732.11	$2,313	$2,947
		Primary Customers	155	Customers	$727.44	$113	$144
FACILITIES	Feeder Backbone		510,040	kW, rateclass peak	$21.13	$10,777	$13,729
	Feeder Local Facilities		669,607	Design Demand	$7.00	$4,687	$5,971
DEMAND	Subtransmission		516,722	kW, rateclass peak	$10.99	$5,679	$7,234
	Substation		510,040	kW, rateclass peak	$10.12	$5,162	$6,575
SUBTOTAL						$29,147	$37,131

PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION COST
2014

Grouping			Usages	Units & Basis	Marginal Unit Cost	Marginal Cost Revenues	Class Revenue Requirement
Schedule 85 General Service (1,001-4,000 kW)							
CUSTOMER	Meters						
		Secondary Meters	80	Customers	$164.19	$13	$17
		Primary Meters	79	Customers	$1,382.27	$110	$140
	Service & Transformer						
		Secondary Customers	80	Customers	$4,581.85	$367	$467
		Primary Customers	79	Customers	$867.23	$69	$88
FACILITIES	Feeder Backbone		213,587	kW, rateclass peak	$21.14	$4,515	$5,752
	Feeder Local Facilities		264,530	Design Demand	$4.66	$1,233	$1,570
DEMAND	Subtransmission		216,385	kW, rateclass peak	$10.99	$2,378	$3,029
	Substation		213,587	kW, rateclass peak	$10.12	$2,162	$2,754
SUBTOTAL						$10,846	$13,817
Schedule 89 General Service (4,000 plus kW)							
CUSTOMER	Meters						
		Secondary Meters	2	Customers	$164.19	$0	$0
		Primary Meters	31	Customers	$1,382.27	$43	$55
		Substation Meters	8	Customers	$16,556.61	$132	$169
	Service & Transformer						
		Secondary Customers	2	Customers	$11,054.47	$22	$28
		Primary Customers	31	Customers	$2,548.39	$79	$101
FACILITIES	Feeder Backbone						
		Secondary Customers	2	Customers	$73,144.00	$146	$186
		Primary Customers	31	Customers	$73,144.00	$2,267	$2,889
		Subtransmission 115 kV Feeder	8	Customers	$83,464.00	$668	$851
DEMAND	Subtransmission		453,534	kW, rateclass peak	$10.99	$4,984	$6,350
	Substation (Sec. & Prim. Only)		374,623	kW, rateclass peak	$10.12	$3,791	$4,830
SUBTOTAL						$12,134	$15,457
Schedules 91 & 95 Streetlighting & Highway Lighting							
CUSTOMER	Customer Service		158,628	Lights	$3.39	$537	$684
	Service & Transformer		158,628	Lights	$5.01	$795	$1,012
FACILITIES	Feeder Backbone		27,068	kW, rateclass peak	$25.26	$684	$871
	Feeder Local Facilities		27,068	Design Demand	$17.81	$482	$614
DEMAND	Subtransmission		27,422	kW, rateclass peak	$10.99	$301	$384
	Substation		27,068	kW, rateclass peak	$10.12	$274	$349
FIXED	Luminaires & Poles						**$7,946**
SUBTOTAL						$3,073	$11,861

PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION COST
2014

Grouping		Usages	Units & Basis	Marginal Unit Cost	Marginal Cost Revenues	Class Revenue Requirement
Schedule 92 Traffic Signals						
CUSTOMER	Service & Transformer	1,772	Intersections	$12.09	$21	$27
FACILITIES	Feeder Backbone	531	kW, rateclass peak	$25.26	$13	$17
	Feeder Local Facilities	531	Design Demand	$9.09	$5	$6
DEMAND	Subtransmission	538	kW, rateclass peak	$10.99	$6	$8
	Substation	531	kW, rateclass peak	$10.12	$5	$7
SUBTOTAL					$51	$65
Schedule 93 Stadium Lighting						
CUSTOMER	Meters	24	Customers	$1,296.40	$31	$40
	Service & Transformer	24	Customers	$72.37	$2	$2
FACILITIES	Feeder Backbone	1,017	kW, rateclass peak	$25.26	$26	$33
	Feeder Local Facilities	1,956	Design Demand	$9.09	$18	$23
DEMAND	Subtransmission	1,030	kW, rateclass peak	$10.99	$11	$14
	Substation	1,017	kW, rateclass peak	$10.12	$10	$13
SUBTOTAL					$98	$125
Summary						
CUSTOMER	Meters	840,466	Customers		$20,567	$26,201
	Service & Transformer		Customers		$92,561	$117,915
	Customer Service	179,249	Lights		$607	$773
FACILITIES	Feeder Backbone	3,718,407	kW, rateclass peak		$96,218	$122,574
	Feeder Local Facilities	5,592,682	Design Demand		$78,868	$100,472
DEMAND	Subtransmission	4,220,651	kW, rateclass peak		$46,385	$59,091
	Substation	4,093,030	kW rateclass Peak		$41,421	$52,768
FIXED	Luminaires & Poles					$10,463
TOTALS					$376,627	$490,257
					TARGET	$490,257
				EQUAL PERCENT		127.4%

PORTLAND GENERAL ELECTRIC
ALLOCATION OF METERING REVENUE REQUIREMENT
2014

Grouping	Customers	Marginal Unit Cost $ per Customer	Marginal Cost Revenues	Class Revenue Requirement
Schedule 7				
Single Phase	733,968	$0.45	$330	$2,465
Three Phase	82	$0.45	$0	$0
Schedule 15				
Residential	882	$0.00	$0	$0
Commercial	1,372	$0.00	$0	$0
Schedule 32				
Single Phase	53,942	$1.01	$54	$407
Three Phase	34,854	$1.01	$35	$263
Schedule 38				
Single Phase	38	$12.96	$0	$4
Three Phase	238	$12.96	$3	$23
Schedule 47				
Single Phase	220	$0.93	$0	$2
Three Phase	2,983	$0.93	$3	$21
Schedule 49				
Single Phase	4	$1.50	$0	$0
Three Phase	1,292	$1.50	$2	$14
Schedule 83				
Single Phase	697	$5.06	$4	$26
Three Phase	10,433	$5.06	$53	$394
Schedule 85				
Secondary	1,335	$10.72	$14	$107
Primary	155	$10.72	$2	$12
Schedule 85 1-4 MW				
Secondary	80	$7.65	$1	$5
Primary	79	$7.65	$1	$5
Schedule 89 GT 4 MW				
Secondary	2	$0.00	$0	$0
Primary	31	$0.00	$0	$0
Subtransmission	8	$0.00	$0	$0
Schedules 91/95	205	$0.00	$0	$0
Schedule 92	17	$0.00	$0	$0
Schedule 93	24	$9.49	$0	$2
TOTAL	842,942		$502	$3,748
			TARGET	$3,748
		EQUAL PERCENT		746%

PORTLAND GENERAL ELECTRIC
ALLOCATION OF BILLING REVENUE REQUIREMENT
2014

Grouping	Customers	Marginal Unit Cost $ per Customer	Marginal Cost Revenues	Class Revenue Requirement
Schedule 7				
Single Phase	733,968	$51.80	$38,020	$49,880
Three Phase	82	$51.80	$4	$6
Schedule 15				
Residential	882	$40.24	$35	$47
Commercial	1,372	$63.54	$87	$114
Schedule 32				
Single Phase	53,942	$68.21	$3,679	$4,827
Three Phase	34,854	$68.21	$2,377	$3,119
Schedule 38				
Single Phase	38	$43.06	$2	$2
Three Phase	238	$43.06	$10	$13
Schedule 47				
Single Phase	220	$65.81	$14	$19
Three Phase	2,983	$65.81	$196	$258
Schedule 49				
Single Phase	4	$77.18	$0	$0
Three Phase	1,292	$77.18	$100	$131
Schedule 83				
Single Phase	697	$89.18	$62	$82
Three Phase	10,433	$89.18	$930	$1,221
Schedule 85				
Secondary	1,335	$43.29	$58	$76
Primary	155	$43.29	$7	$9
Schedule 85 1-4 MW				
Secondary	80	$43.52	$3	$5
Primary	79	$43.52	$3	$5
Schedule 89 GT 4 MW				
Secondary	2	$43.13	$0	$0
Primary	31	$43.13	$1	$2
Subtransmission	8	$43.13	$0	$0
Schedules 91/95	205	$436.03	$89	$117
Schedule 92	17	$436.03	$7	$10
Schedule 93	24	$63.96	$2	$2
TOTAL	842,942		$45,690	$59,943
			TARGET	$59,943
		EQUAL PERCENT		131%

PORTLAND GENERAL ELECTRIC
ALLOCATION OF CONSUMER REVENUE REQUIREMENT
2014

Grouping	Customers	Marginal Unit Cost $ per Customer	Marginal Cost Revenues	Class Revenue Requirement
Schedule 7				
Single Phase	733,968	$20.17	$14,804	$32,477
Three Phase	82	$20.17	$2	$4
Schedule 15				
Residential	882	$20.16	$18	$39
Commercial	1,372	$36.63	$50	$110
Schedule 32				
Single Phase	53,942	$46.31	$2,498	$5,480
Three Phase	34,854	$46.31	$1,614	$3,541
Schedule 38				
Single Phase	38	$50.52	$2	$4
Three Phase	238	$50.52	$12	$26
Schedule 47				
Single Phase	220	$38.47	$8	$19
Three Phase	2,983	$38.47	$115	$252
Schedule 49				
Single Phase	4	$41.25	$0	$0
Three Phase	1,292	$41.25	$53	$117
Schedule 83				
Single Phase	697	$83.99	$59	$128
Three Phase	10,433	$83.99	$876	$1,922
Schedule 85				
Secondary	1,335	$824.75	$1,101	$2,416
Primary	155	$824.75	$128	$280
Schedule 85 1-4 MW				
Secondary	80	$3,554.04	$284	$624
Primary	79	$3,554.04	$282	$619
Schedule 89 GT 4 MW				
Secondary	2	$41,182.48	$82	$181
Primary	31	$41,182.48	$1,277	$2,801
Subtransmission	8	$41,182.48	$329	$723
Schedule 91/95	205	$334.22	$69	$150
Schedule 92	17	$188.87	$3	$7
Schedule 93	24	$101.58	$2	$5
TOTAL	842,942		$23,669	$51,926
			TARGET	$51,926
		EQUAL PERCENT		219%

PORTLAND GENERAL ELECTRIC

PROPOSED
Summary of Area and Streetlighting Revenue

Schedule 15 - Area Lighting	
Fixtures & Maintenance	$1,673,437
Poles	$843,213
Energy (volumetric c/kWh rate)	$2,297,067
Total	**$4,813,717**

Schedule 91/95 - Street and Highway Lighting	
Fixtures & Maintenance (Options A&B)	$4,235,123
Poles (Options A&B)	$3,711,060
Energy (volumetric c/kWh rate)	$10,236,644
Total	**$18,182,827**

PORTLAND GENERAL ELECTRIC
Schedules 91 & 95, Proposed Prices, Counts and Revenue

Lum				Monthly		Tariff Rates		Monthly	Proposed Sch 91 & 95 A & B Counts				Annual	Annual Fixed Revenue		Annual
CODE	Light Description	Type	Watts	kWh	Category	A	B	Energy	A	B	C	TOTAL	MWh	A	B	Energy
79	Cobrahead - PD	HPS	70-watt	30	Standard	*	**$1.28**	**$2.98**	-	1	-	1	30	*	$15	$36
84	Cobrahead - PD	HPS	100-watt	43	Standard	*	**$1.29**	**$4.28**	-	28,681	982	29,663	43	*	$443,982	$1,523,492
85	Cobrahead - PD	HPS	150-watt	62	Standard	*	**$1.30**	**$6.16**	-	1,845	505	2,350	62	*	$28,782	$173,712
89	Cobrahead - PD	HPS	200-watt	79	Standard	*	**$1.36**	**$7.85**	-	5,146	318	5,464	79	*	$83,983	$514,709
86	Cobrahead - PD	HPS	250-watt	102	Standard	*	**$1.37**	**$10.14**	-	2,479	908	3,387	102	*	$40,755	$412,130
87	Cobrahead - PD	HPS	400-watt	163	Standard	*	**$1.39**	**$16.21**	-	1,861	68	1,929	163	*	$31,041	$375,229
33	Cobrahead	HPS	70-watt	30	Standard	**$5.20**	**$1.53**	**$2.98**	456	889	1,034	2,379	30	$28,454	$16,322	$85,073
34	Cobrahead	HPS	100-watt	43	Standard	**$5.14**	**$1.52**	**$4.28**	4,807	16,258	723	21,788	43	$296,496	$296,546	$1,119,032
35	Cobrahead	HPS	150-watt	62	Standard	**$5.17**	**$1.53**	**$6.16**	337	7,370	825	8,532	62	$20,907	$135,313	$630,685
39	Cobrahead	HPS	200-watt	79	Standard	**$5.80**	**$1.58**	**$7.85**	1,091	6,157	1,162	8,410	79	$75,934	$116,737	$792,222
36	Cobrahead	HPS	250-watt	102	Standard	**$5.94**	**$1.61**	**$10.14**	169	2,778	1,245	4,192	102	$12,046	$53,671	$510,083
37	Cobrahead	HPS	400-watt	163	Standard	**$6.32**	**$1.64**	**$16.21**	859	1,848	433	3,140	163	$65,147	$36,369	$610,793
31	Flood	HPS	250-watt	102	Standard	**$6.73**	**$1.70**	**$10.14**	128	2	-	130	102	$10,337	$41	$15,818
32	Flood	HPS	400-watt	163	Standard	**$6.72**	**$1.69**	**$16.21**	311	38	10	359	163	$25,079	$771	$69,833
40	Post-Top	HPS	100-watt	43	Standard	**$5.92**	**$1.60**	**$4.28**	4,759	4,839	863	10,461	43	$338,079	$92,909	$537,277
76	Shoebox	HPS	70-watt	30	Standard	**$6.65**	**$1.70**	**$2.98**	24	98	-	122	30	$1,915	$1,999	$4,363
77	Shoebox	HPS	100-watt	43	Standard	**$6.83**	**$1.72**	**$4.28**	2,348	5,871	2,251	10,470	43	$192,442	$121,177	$537,739
78	Shoebox	HPS	150-watt	62	Standard	**$7.14**	**$1.77**	**$6.16**	207	442	131	780	62	$17,736	$9,388	$57,658
81	Special Acorn	HPS	100-watt	43	Custom	**$10.27**	**$2.08**	**$4.28**	986	4,490	472	5,948	43	$121,515	$112,070	$305,489
82	Victorian	HPS	150-watt	62	Custom	**$10.29**	**$2.10**	**$6.16**	64	2,055	196	2,315	62	$7,903	$51,786	$171,125
49	Victorian	HPS	200-watt	79	Custom	**$11.06**	**$2.22**	**$7.85**	3	134	-	137	79	$398	$3,570	$12,905
83	Victorian	HPS	250-watt	102	Custom	**$11.07**	**$2.22**	**$10.14**	76	1,170	-	1,246	102	$10,096	$31,169	$151,613
64	Capitol Acorn	HPS	100-watt	43	Custom	**$14.39**	**$2.56**	**$4.28**	-	65	-	65	43	$0	$1,997	$3,338
67	Capitol Acorn	HPS	150-watt	62	Custom	**$14.44**	**$2.61**	**$6.16**	-	253	-	253	62	$0	$7,924	$18,702
65	Capitol Acorn	HPS	200-watt	79	Custom	**$14.31**	**$2.60**	**$7.85**	-	70	-	70	79	$0	$2,184	$6,594
66	Capitol Acorn	HPS	250-watt	102	Custom	**$14.33**	**$2.61**	**$10.14**	-	-	-	0	102	$0	$0	$0
12	Acorn - Indep.	HPS	100-watt	43	Custom	**$10.40**	**$2.08**	**$4.28**	38	1	-	39	43	$4,742	$25	$2,003
13	Acorn - Indep.	HPS	150-watt	62	Custom	**$10.07**	**$2.05**	**$6.16**	-	-	-	0	62	$0	$0	$0
98	Techtra	HPS	100-watt	43	Custom	**$19.52**	**$3.14**	**$4.28**	498	38	-	536	43	$116,652	$1,432	$27,529
99	Techtra	HPS	150-watt	62	Custom	**$19.19**	**$3.12**	**$6.16**	12	65	-	77	62	$2,763	$2,434	$5,692
88	Techtra	HPS	250-watt	102	Custom	**$18.53**	**$3.08**	**$10.14**	-	150	-	150	102	$0	$5,544	$18,252
90	Westbrooke Acorn	HPS	70-watt	30	Custom	**$13.34**	**$2.43**	**$2.98**	1	25	-	26	30	$160	$729	$930
91	Westbrooke Acorn	HPS	100-watt	43	Custom	**$13.09**	**$2.40**	**$4.28**	-	11	-	11	43	$0	$317	$565
92	Westbrooke Acorn	HPS	150-watt	62	Custom	**$13.10**	**$2.41**	**$6.16**	-	26	-	26	62	$0	$752	$1,922
93	Westbrooke Acorn	HPS	200-watt	79	Custom	**$13.39**	**$2.48**	**$7.85**	-	2	-	2	79	$0	$60	$188
94	Westbrooke Acorn	HPS	250-watt	102	Custom	**$13.27**	**$2.47**	**$10.14**	73	35	-	108	102	$11,625	$1,037	$13,141
62	Cobrahead	MH	150-watt	60	Custom	**$5.80**	**$1.84**	**$5.97**	-	-	-	0	60	$0	$0	$0
61	Flood	MH	350-watt	139	Custom	**$8.16**	**$2.15**	**$13.82**	-	-	-	0	139	$0	$0	$0
47	Flood	HPS	750-watt	285	Custom	**$10.25**	**$2.69**	**$28.33**	54	-	-	54	285	$6,642	$0	$18,358
9	Mongoose	HPS	150-watt	62	Custom	**$10.77**	**$2.15**	**$6.16**	-	27	-	27	62	$0	$697	$1,996
10	Mongoose	HPS	250-watt	102	Custom	**$10.07**	**$2.09**	**$10.14**	-	8	-	8	102	$0	$201	$973
18	Ornamental Acorn Twin / Opt C	QL	85-watt	64	Custom	*	*	**$6.36**	-	-	565	565	64	*	*	$43,121
20	Ornamental Acorn / Opt C	QL	55-watt	21	Custom	*	*	**$2.09**	-	-	5	5	21	*	*	$125
26	Ornamental Acorn Twin / Opt C	QL	55-watt	42	Custom	*	*	**$4.18**	-	-	4	4	42	*	*	$201
44	Composite Twin / Opt C	Comp	140-watt	54	Custom	*	*	**$5.37**	-	-	15	15	54	*	*	$967
45	Composite Twin / Opt C	Comp	175-watt	66	Custom	*	*	**$6.56**	-	-	16	16	66	*	*	$1,260
19	Cobrahead - (C) Only	MV	100-watt	39	Obsolete	*	*	**$3.88**	-	-	1	1	39	*	*	$47
21	Cobrahead	MV	175-watt	66	Obsolete	**$5.08**	**$1.46**	**$6.56**	432	1,308	86	1,826	66	$26,335	$22,916	$143,743
22	Cobrahead	MV	250-watt	94	Obsolete	*	*	**$9.35**	-	-	23	23	94	*	*	$2,581
23	Cobrahead	MV	400-watt	147	Obsolete	**$5.82**	**$1.60**	**$14.61**	302	67	81	450	147	$21,092	$1,286	$78,894
24	Cobrahead	MV	1,000-watt	374	Obsolete	**$6.60**	**$1.92**	**$37.18**	13	7	2	22	374	$1,030	$161	$9,816

PORTLAND GENERAL ELECTRIC
Schedules 91 & 95, Proposed Prices, Counts and Revenue

Lum CODE	Light Description	Type	Watts	Monthly kWh	Category	Tariff Rates A	Tariff Rates B	Monthly Energy	Proposed Sch 91 & 95 A & B Counts A	B	C	TOTAL	Annual MWh	Annual Fixed Revenue A	Annual Fixed Revenue B	Annual Energy
50	Special Box - Space-Glo	HPS	70-watt	30	Obsolete	**$6.73**	**$1.62**	**$2.98**	21	-	-	21	30	$1,696	$0	$751
46	Special Box - Space-Glo	MV	175-watt	66	Obsolete	**$6.68**	**$1.57**	**$6.56**	19	138	47	204	66	$1,523	$2,600	$16,059
51	Box - Gardco Hub / Opt C	HPS	Twin 70-watt	60	Obsolete	*	*	**$5.97**	-	-	116	116	60	*	*	$8,310
52	Box - Gardco Hub / Opt C	HPS	70-watt	30	Obsolete	*	*	**$2.98**	-	-	211	211	30	*	*	$7,545
53	Box - Gardco Hub	HPS	100-watt	43	Obsolete	*	**$1.97**	**$4.28**	-	5	-	5	43	*	$118	$257
54	Box - Gardco Hub	HPS	150-watt	62	Obsolete	*	**$1.99**	**$6.16**	-	62	41	103	62	*	$1,481	$7,614
55	Box - Gardco Hub / Opt C	HPS	250-watt	102	Obsolete	*	*	**$10.14**	-	-	234	234	102	*	*	$28,473
56	Box - Gardco Hub / Opt C	HPS	400-watt	163	Obsolete	*	*	**$16.21**	-	-	111	111	163	*	*	$21,592
58	Box - Gardco Hub	MH	250-watt	99	Obsolete	*	**$1.20**	**$9.84**	-	7	3	10	99	*	$101	$1,181
59	Box - Gardco Hub	MH	400-watt	156	Obsolete	*	**$1.20**	**$15.51**	-	26	-	26	156	*	$374	$4,839
48	Cobrahead	MH	175-watt	71	Obsolete	**$6.08**	**$1.69**	**$7.06**	-	3	57	60	71	$0	$61	$5,083
60	Flood	MH	400-watt	156	Obsolete	**$6.94**	**$1.74**	**$15.51**	23	3	2	28	156	$1,915	$63	$5,211
69	Cobrahead DW 70/100	HPS	100-watt	43	Obsolete	*	**$1.53**	**$4.28**	-	89	-	89	43	*	$1,634	$4,571
70	Cobrahead DW 100/150	HPS	100-watt	43	Obsolete	*	**$1.53**	**$4.28**	-	405	-	405	43	*	$7,436	$20,801
71	Cobrahead DW 100/150	HPS	150-watt	62	Obsolete	*	**$1.55**	**$6.16**	-	303	5	308	62	*	$5,636	$22,767
2	Victorian	QL	85-watt	32	Obsolete	*	**$0.67**	**$3.18**	-	11	271	282	32	*	$88	$10,761
1	Victorian	QL	165-watt	60	Obsolete	*	**$0.94**	**$5.97**	-	104	113	217	60	*	$1,173	$15,546
3	Techtra	QL	165-watt	60	Obsolete	**$23.22**	**$1.14**	**$5.97**	4	152	-	156	60	$1,115	$2,079	$11,176
95	KIM SBC Shoebox	HPS	150-watt	62	Obsolete	*	**$2.55**	**$6.16**	-	35	66	101	62	*	$1,071	$7,466
96	KIM Archetype	HPS	250-watt	102	Obsolete	*	**$2.81**	**$10.14**	-	65	23	88	102	*	$2,192	$10,708
97	KIM Archetype	HPS	400-watt	163	Obsolete	*	**$2.20**	**$16.21**	-	20	28	48	163	*	$528	$9,337
80	Acorn Type	HPS	70-watt	30	Obsolete	**$10.25**	**$2.06**	**$2.98**	24	7	-	31	30	$2,952	$173	$1,109
73	GardCo Bronze - (C) Only	HPS	70-watt	30	Obsolete	*	*	**$2.98**	-	-	30	30	30	*	*	$1,073
72	GardCo Bronze - (C) Only	MV	175-watt	66	Obsolete	*	*	**$6.56**	-	-	136	136	66	*	*	$10,706
74	Acrylic Sphere - (C) Only	MV	400-watt	147	Obsolete	*	*	**$14.61**	-	-	-	0	147	*	*	$0
25	Post-Top - Black	HPS	70-watt	30	Obsolete	**$5.81**	**$1.49**	**$2.98**	1,507	1,266	-	2,773	30	$105,068	$22,636	$99,162
43	Rect.Type - (C) Only	HPS	200-watt	79	Obsolete	*	*	**$7.85**	-	-	169	169	79	*	*	$15,920
5	Incand. - (C) Only	IND	92-watt	31	Obsolete	*	*	**$3.08**	-	-	25	25	31	*	*	$924
6	Incand. - (C) Only	IND	182-watt	62	Obsolete	*	*	**$6.16**	-	-	4	4	62	*	*	$296
29	Town and Country Post-Top	MV	175-watt	66	Obsolete	**$5.82**	**$1.50**	**$6.56**	92	1,134	5	1,231	66	$6,425	$20,412	$96,904
27	Flood	HPS	70-watt	30	Obsolete	**$5.20**	**$1.58**	**$2.98**	-	-	-	0	30	$0	$0	$0
30	Flood	HPS	100-watt	43	Obsolete	**$5.17**	**$1.52**	**$4.28**	46	7	-	53	43	$2,854	$128	$2,722
38	Flood	HPS	200-watt	79	Obsolete	**$6.69**	**$1.66**	**$7.85**	176	42	-	218	79	$14,129	$837	$20,536
41	Cobrahead - PD	HPS	310-watt	124	Obsolete	**$6.33**	**$2.00**	**$12.33**	5	21	-	26	124	$380	$504	$3,847
14	Ornamental - (C) Only	HPS	100-watt	43	Obsolete	*	*	**$4.28**	-	-	1,775	1,775	43	*	*	$91,164
15	Twin Ornamental -(C) Only	HPS	Twin 100-watt	86	Obsolete	*	*	**$8.55**	-	-	2,330	2,330	86	*	*	$239,058
7	Flourescent - (C) Only	FLR	28-watt	12	Obsolete	*	*	**$1.19**	-	-	13	13	12	*	*	$186
100	Cobrahead	LED	37-watt	13	Standard	**$3.46**	*	**$1.29**	1,187	-	-	1,187	13	$49,284	*	$18,375
101	Cobrahead	LED	50-watt	17	Standard	**$3.46**	*	**$1.69**	13,925	-	-	13,925	17	$578,166	*	$282,399
102	Cobrahead	LED	52-watt	18	Standard	**$3.88**	*	**$1.79**	908	-	-	908	18	$42,276	*	$19,504
103	Cobrahead	LED	67-watt	23	Standard	**$4.36**	*	**$2.29**	2,896	-	-	2,896	23	$151,519	*	$79,582
104	Cobrahead	LED	106-watt	36	Standard	**$5.22**	*	**$3.58**	493	-	-	493	36	$30,882	*	$21,179
								Totals	**39,374**	**100,515**	**18,739**	**158,628**	**6,946**	**$2,405,708**	**$1,829,415**	**$10,236,644**

Notes:
1. Obsolete fixtures are not available to new service
2. Option C are customer owned and maintained and only pay the respective energy charge

PORTALND GENERAL ELECTRIC

Schedule 91 Poles, Forecasted Revenue at Proposed Prices

Pole CODE	Pole Description	Material	Pole Height	Option	Tariff Rates	Counts	Annual Revenues
57	Black	Fiberglass	20	A	$6.51	2,242	$175,145
59	Bronze	Fiberglass	30	A	$10.26	2,541	$312,848
61	Gray	Fiberglass	30	A	$11.07	3,150	$418,446
1	Standard	Wood	30 to 35	A	$7.40	3,947	$350,494
3	Standard	Wood	40 to 55	A	$9.70	620	$72,168
58	Black	Fiberglass	20	B	$0.19	5,364	$12,230
60	Bronze	Fiberglass	30	B	$0.29	6,555	$22,811
62	Gray	Fiberglass	30	B	$0.32	11,999	$46,076
46	Standard	Wood	30 to 35	B	$0.21	1,006	$2,535
47	Standard	Wood	40 to 55	B	$0.28	209	$702
31	Regular	Aluminum	16	A	$8.86	568	$60,390
32	Regular	Aluminum	25	A	$14.70	5,370	$947,268
33	Regular	Aluminum	30	A	$15.89	276	$52,628
28	Regular	Aluminum	35	A	$19.02	92	$20,998
18	Davit	Aluminum	25	A	$14.67	74	$13,027
6	Davit	Aluminum	30	A	$14.60	448	$78,490
29	Davit	Aluminum	35	A	$15.97	179	$34,304
70	Davit with 8-foot Arm	Aluminum	40	A	$21.68	9	$2,341
27	Double Davit	Aluminum	30	A	$21.58	22	$5,697
65	Fluted Victorian Ornamental	Aluminum	14	A	$12.99	36	$5,612
69	Non-fluted Techtra Ornamental	Aluminum	18	A	$25.57	527	$161,705
66	Fluted Ornamental	Aluminum	16	A	$13.28	101	$16,095
77	HADCO Non-fluted Ornamental	Aluminum	16	A	$27.18	1	$326
79	Fluted Westbrooke	Aluminum	18	A	$25.64	0	$0
81	Non-fluted Westbrooke	Aluminum	18	A	$27.18	73	$23,810
43	Painted Ornamental - Portland Rd.	Aluminum	35	A	$43.67	0	$0
85	Decorative Ameron	Concrete	20	A	$25.51	0	$0
4	Ameron Post Top	Concrete	25	A	$25.51	0	$0
63	Fluted Ornamental -Black	Fiberglass	14	A	$15.70	645	$121,518
83	Smooth	Fiberglass	18	A	$6.48	0	$0
67	Regular - Color may vary	Fiberglass	22	A	$5.80	22	$1,531
68	Regular - Color may vary	Fiberglass	35	A	$9.53	157	$17,955
16	Anchor Base -Gray	Fiberglass	35	A	$17.45	34	$7,120
35	Direct Bury with Shroud	Fiberglass	18	A	$10.50	4	$504
34	Regular	Aluminum	16	B	$0.25	109	$327
8	Regular	Aluminum	25	B	$0.42	2,012	$10,140
48	Regular	Aluminum	30	B	$0.45	701	$3,785
54	Regular	Aluminum	35	B	$0.54	565	$3,661
13	Davit	Aluminum	25	B	$0.42	125	$630
12	Davit	Aluminum	30	B	$0.42	1,537	$7,746
53	Davit	Aluminum	35	B	$0.46	2,011	$11,101
76	Davit with 8-foot Arm	Aluminum	40	B	$0.62	205	$1,525
14	Double Davit	Aluminum	30	B	$0.62	63	$469
71	Fluted Victorian Ornamental	Aluminum	14	B	$0.37	1,165	$5,173
75	Non-fluted Techtra Ornamental	Aluminum	18	B	$0.73	444	$3,889
72	Fluted Ornamental	Aluminum	16	B	$0.38	1,830	$8,345

PORTALND GENERAL ELECTRIC

Schedule 91 Poles, Forecasted Revenue at Proposed Prices

Pole CODE	Pole Description	Material	Pole Height	Option	Tariff Rates	Counts	Annual Revenues
78	HADCO Non-fluted Ornamental	Aluminum	16	B	$0.78	42	$393
80	Fluted Westbrooke	Aluminum	18	B	$0.73	20	$175
82	Non-fluted Westbrooke	Aluminum	18	B	$0.78	48	$449
44	Painted Ornamental - Portland Rd.	Aluminum	35	B	$1.25	62	$930
86	Decorative Ameron	Concrete	20	B	$0.73	0	$0
5	Ameron Post Top	Concrete	25	B	$0.73	49	$429
64	Fluted Ornamental -Black	Fiberglass	14	B	$0.45	2,148	$11,599
84	Smooth	Fiberglass	18	B	$0.19	0	$0
73	Regular - Color may vary	Fiberglass	22	B	$0.17	513	$1,047
74	Regular - Color may vary	Fiberglass	35	B	$0.27	1,890	$6,124
17	Anchor Base -Gray	Fiberglass	35	B	$0.50	63	$378
36	Direct Bury with Shroud	Fiberglass	18	B	$0.30	552	$1,987
2	Post	Aluminum	30	A	$8.86	601	$63,898
30	Ornamental Post	Concrete	35 or less	A	$14.70	59	$10,408
37	Painted Regular	Steel	25	A	$14.70	594	$104,782
38	Painted Regular	Steel	30	A	$15.89	195	$37,183
39	Laminated without Mast Arm	Wood	20	A	$6.51	2,891	$225,845
24	Laminted SLO Pole	Wood	20	A	$6.51	299	$23,358
41	Curved laminated	Wood	30	A	$10.26	924	$113,763
11	Painted Underground	Wood	35	A	$7.40	544	$48,307
22	Painted SLO Pole	Wood	35	A	$7.40	50	$4,440
55	Bronze Alloy GardCo	Bronze	12	B	$0.23	21	$58
25	Ornamental Post	Concrete	35 or less	B	$0.42	288	$1,452
7	Painted Regular	Steel	25	B	$0.42	378	$1,905
49	Painted Regular	Steel	30	B	$0.45	48	$259
21	Unpainted with 6-foot Mast Arm	Steel	30	B	$0.42	55	$277
51	Unpainted with 6-foot Davit Arm	Steel	30	B	$0.42	43	$217
40	Unpainted with 8-foot Mast Arm	Steel	35	B	$0.46	118	$651
42	Unpainted with 8-foot Davit Arm	Steel	35	B	$0.46	18	$99
23	Laminated without Mast Arm	Wood	20	B	$0.19	2,433	$5,547
45	Curved laminated	Wood	30	B	$0.29	142	$494
26	Painted Underground	Wood	35	B	$0.21	1,207	$3,042
				Total Option As		27,295	$3,532,401
				Total Option Bs		46,038	$178,660
						73,333	$3,711,060

PORTLAND GENERAL ELECTRIC
Schedule 15, Proposed Tariff Prices, Counts and Revenue

Code	Description	Type	Size	kWh	Monthly Tariff Price Fixed	Energy	Total	Count	Annual MWh	Revenues Fixed	Energy	Total
Fixtures												
21	Cobrahead	MV	175-watt	66	$6.22	$6.56	$12.78	3,110	2,463	$232,130	$244,819	$476,950
23	Cobrahead	MV	400-watt	147	$6.49	$14.61	$21.10	2,812	4,960	$218,999	$493,000	$711,998
24	Cobrahead	MV	1000-watt	374	$7.28	$37.18	$44.46	109	489	$9,522	$48,631	$58,154
33	Cobrahead - (non-pd)	HPS	70-watt	30	$6.34	$2.98	$9.32	1,073	386	$81,634	$38,370	$120,004
34	Cobrahead - (non-pd)	HPS	100-watt	43	$6.28	$4.28	$10.56	3,379	1,744	$254,641	$173,545	$428,187
35	Cobrahead - (non-pd)	HPS	150-watt	62	$6.31	$6.16	$12.47	949	706	$71,858	$70,150	$142,008
39	Cobrahead - (non-pd)	HPS	200-watt	79	$6.47	$7.85	$14.32	1,829	1,734	$142,004	$172,292	$314,295
36	Cobrahead - (non-pd)	HPS	250-watt	102	$6.62	$10.14	$16.76	640	783	$50,842	$77,875	$128,717
41	Cobrahead - (PD)	HPS	310-watt	124	$7.01	$12.33	$19.34	6	9	$505	$888	$1,392
37	Cobrahead - (non-pd)	HPS	400-watt	163	$7.00	$16.21	$23.21	1,710	3,345	$143,640	$332,629	$476,269
30	Flood	HPS	100-watt	43	$6.31	$4.28	$10.59	393	203	$29,758	$20,184	$49,942
38	Flood	HPS	200-watt	79	$7.37	$7.85	$15.22	619	587	$54,744	$58,310	$113,054
31	Flood	HPS	250-watt	102	$7.41	$10.14	$17.55	807	988	$71,758	$98,196	$169,954
32	Flood	HPS	400-watt	163	$7.39	$16.21	$23.60	1,844	3,607	$163,526	$358,695	$522,221
76	Shoebox	HPS	70-watt	30	$7.79	$2.98	$10.77	0	0	$0	$0	$0
77	Shoebox	HPS	100-watt	43	$7.97	$4.28	$12.25	581	300	$55,567	$29,840	$85,407
78	Shoebox	HPS	150-watt	62	$8.28	$6.16	$14.44	93	69	$9,240	$6,875	$16,115
81	Special Acorn	HPS	100-watt	43	$10.95	$4.28	$15.23	363	187	$47,698	$18,644	$66,342
82	HADCO - Victorian	HPS	150-watt	62	$10.96	$6.16	$17.12	16	12	$2,104	$1,183	$3,287
49	HADCO - Victorian	HPS	200-watt	79	$11.73	$7.85	$19.58	0	0	$0	$0	$0
83	HADCO - Victorian	HPS	250-watt	102	$11.75	$10.14	$21.89	0	0	$0	$0	$0
40	Early American Post-Top	HPS	100-watt	43	$7.05	$4.28	$11.33	83	43	$7,022	$4,263	$11,285
62	Cobrahead	MH	150-watt	60	$6.93	$5.97	$12.90	0	0	$0	$0	$0
48	Cobrahead	MH	175-watt	71	$7.22	$7.06	$14.28	24	20	$2,079	$2,033	$4,113
61	Flood	MH	350-watt	139	$8.83	$13.82	$22.65	0	0	$0	$0	$0
60	Flood	MH	400-watt	156	$7.62	$15.51	$23.13	14	26	$1,280	$2,606	$3,886
47	Flood	HPS	750-watt	285	$10.93	$28.33	$39.26	121	414	$15,870	$41,135	$57,006
12	HADCO Independence	HPS	100-watt	43	$11.08	$4.28	$15.36	10	5	$1,330	$514	$1,843
13	HADCO Independence	HPS	150-watt	62	$10.75	$6.16	$16.91	20	15	$2,580	$1,478	$4,058
64	HADCO Capitol Acorn	HPS	100-watt	43	$15.06	$4.28	$19.34	9	5	$1,626	$462	$2,089
67	HADCO Capitol Acorn	HPS	150-watt	62	$15.12	$6.16	$21.28	0	0	$0	$0	$0
65	HADCO Capitol Acorn	HPS	200-watt	79	$14.99	$7.85	$22.84	0	0	$0	$0	$0
66	HADCO Capitol Acorn	HPS	250-watt	102	$15.00	$10.14	$25.14	0	0	$0	$0	$0
98	HADCO Techtra	HPS	100-watt	43	$20.20	$4.28	$24.48	3	2	$727	$154	$881
99	HADCO Techtra	HPS	150-watt	62	$19.86	$6.16	$26.02	2	1	$477	$148	$624
88	HADCO Techtra	HPS	250-watt	102	$19.21	$10.14	$29.35	0	0	$0	$0	$0
90	HADCO Westbrooke	HPS	70-watt	30	$14.01	$2.98	$16.99	0	0	$0	$0	$0
91	HADCO Westbrooke	HPS	100-watt	43	$13.76	$4.28	$18.04	0	0	$0	$0	$0
92	HADCO Westbrooke	HPS	150-watt	62	$13.78	$6.16	$19.94	0	0	$0	$0	$0
93	HADCO Westbrooke	HPS	200-watt	79	$14.07	$7.85	$21.92	0	0	$0	$0	$0
94	HADCO Westbrooke	HPS	250-watt	102	$13.95	$10.14	$24.09	0	0	$0	$0	$0
96	KIM Archetype	HPS	250-watt	102	$16.94	$10.14	$27.08	0	0	$0	$0	$0
97	KIM Archetype	HPS	400-watt	163	$11.74	$16.21	$27.95	0	0	$0	$0	$0
9	Holophane Mongoose	HPS	150-watt	62	$11.44	$6.16	$17.60	2	1	$275	$148	$422
10	Holophane Mongoose	HPS	250-watt	102	$10.74	$10.14	$20.88	0	0	$0	$0	$0
Totals								20,621	23,104	$1,673,437	$2,297,067	$3,970,505
Poles												
1	Standard	Wood	30 to 35				$7.40	5,669				$503,407
3	Standard	Wood	40 to 55				$9.70	452				$52,613
11	Painted Underground	Wood	35				$7.40	113				$10,034
41	Curved laminated	Wood	30				$9.19	61				$6,727
31	Regular	Aluminum	16				$8.86	26				$2,764
32	Regular	Aluminum	25				$14.70	11				$1,940
33	Regular	Aluminum	30				$15.89	20				$3,814
28	Regular	Aluminum	35				$19.02	3				$685
65	Fluted Ornamental	Aluminum	14				$12.99	19				$2,962
18	Davit	Aluminum	25				$13.60	0				$0
6	Davit	Aluminum	30				$14.60	23				$4,030
29	Davit	Aluminum	35				$15.97	0				$0
70	Davit with 8-foot Arm	Aluminum	40				$21.68	0				$0
27	Double Davit	Aluminum	30				$21.58	3				$777
66	HADCO, Fluted Ornamental	Aluminum	16				$13.28	2				$319
69	HADCO, Non-fluted Techtra Ornamental	Aluminum	18				$25.57	19				$5,830
4	Ameron Post-Top	Concrete	25				$25.51	0				$0
63	Fluted Ornamental Black	Fiberglass	14				$15.70	176				$33,158
57	Regular Black	Fiberglass	20				$6.51	303				$23,670
61	Regular Gray	Fiberglass	30				$11.07	1,292				$171,629
68	Regular Other Colors	Fiberglass	35				$9.53	40				$4,574
16	Anchor Base Gray	Fiberglass	35				$17.45	2				$419
35	Direct Bury with Shroud	Fiberglass	18				$10.50	110				$13,860
Totals								8,344				$843,213
Totals Luminaires and Poles												$4,813,717

PORTLAND GENERAL ELECTRIC
Commercial and Industrial Pricing

	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
Generation Demand						
Schedule 83						
Generation Capacity	$55,189	8,405,722	kW	$6.57	per kW demand	$55,189
Generation Energy	$110,650	2,796,682	MWh	39.56	mills/kWh	$110,650
Total Generation	$165,839					$165,839
Schedule 85						
Generation Capacity	$57,140	8,157,446	kW	$7.00	per kW demand	$57,140
Generation Energy	$123,289	3,165,188	MWh	38.95	mills/kWh	$123,289
Total Generation	$180,429					$180,429
Schedule 89						
Generation Capacity	$35,658	3,941,686	kW	$9.05	per kW demand	$35,658
Generation Energy	$89,544	2,414,106	MWh	37.09	mills/kWh	$89,544
Total Generation	$125,202					$125,202
Schedule 83						
Generation Demand Charge		8,405,722	kW	$6.57	per kW demand	$55,189
Generation Energy		2,796,682	MWh	39.56	mills/kWh	$110,650
Total Generation						$165,839
Schedule 85						
Secondary Generation Demand Charge		6,499,505	kW	$7.05	per kW demand	$45,822
Primary Generation Demand Charge		1,657,941	kW	$6.81	per kW demand	$11,291
Generation Energy		3,165,188	MWh	38.96	mills/kWh	$123,317
Total Generation						$180,429
Schedule 89						
Secondary Generation Demand Charge		62,056	kW	$9.37	per kW demand	$581
Primary Generation Demand Charge		3,457,442	kW	$9.06	per kW demand	$31,324
Subtransmission Generation Demand Charge		422,188	kW	$8.93	per kW demand	$3,770
Generation Energy		2,414,106	MWh	37.08	mills/kWh	$89,526
Total Generation						$125,202

PORTLAND GENERAL ELECTRIC
Commercial and Industrial Pricing

	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
Schedule 83						
Generation Demand		8,405,722	kW	$6.57	per kW demand	$55,226
On-peak Energy		1,807,073	MWh	43.10	mills/kWh	$77,885
Off-peak Energy		989,609	MWh	33.10	mills/kWh	$32,756
Total Generation Charges	$165,839					$165,867
Schedule 85						
Secondary Generation Demand		6,499,505	kW	$7.05	per kW demand	$45,822
Primary Generation Demand		1,657,941	kW	$6.81	per kW demand	$11,291
Secondary On-peak Energy		1,625,951	MWh	42.74	mills/kWh	$69,493
Secondary Off-peak Energy		852,690	MWh	32.74	mills/kWh	$27,917
Primary On-peak Energy		430,280	MWh	41.47	mills/kWh	$17,844
Primary Off-peak Energy		256,267	MWh	31.47	mills/kWh	$8,065
Total Generation Charges	$180,429					$180,431
Schedule 89						
Secondary Generation Demand		62,056	kW	$9.37	per kW demand	$581
Primary Generation Demand		3,457,442	kW	$9.06	per kW demand	$31,324
Subtransmission Generation Demand		422,188	kW	$8.93	per kW demand	$3,770
Secondary On-peak Energy		11,096	MWh	42.53	mills/kWh	$472
Secondary Off-peak Energy		7,177	MWh	32.53	mills/kWh	$233
Primary On-peak Energy		1,269,889	MWh	41.32	mills/kWh	$52,472
Primary Off-peak Energy		921,442	MWh	31.32	mills/kWh	$28,860
Subtransmission On-peak Energy		118,841	MWh	40.82	mills/kWh	$4,851
Subtransmission Off-peak Energy		85,660	MWh	30.82	mills/kWh	$2,640
Total Generation Charges	$125,202					$125,204
Schedule 83, 85, 89 Totals	$471,470					$471,501
On/off Peak Delta				10.00		

Demand and Energy Loss Differentials for Selected Schedules

Schedule 85: Secondary/Primary	Losses				
Embedded energy loss differentials	3.380%		1.27	mills/kWh	
Peak demand loss differential	3.548%		$0.24	per kW demand	
Schedule 89	Sec/Prim	Prim/Subtrans			
Embedded energy loss differentials	3.380%	1.450%	1.21	mills/kWh	Sec/Prim
			1.71	mills/kWh	Sec/Subtrans.
Peak demand loss differentials	3.548%	1.540%	$0.31	per kW demand	Sec/Prim
			$0.44	per kW demand	Sec/Subtrans.

PORTLAND GENERAL ELECTRIC
Commercial and Industrial Pricing

	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
Generation Demand						
Schedule 83						
Generation Capacity	$55,189	8,405,722	kW	$6.57	per kW demand	$55,189
Generation Energy	$110,650	2,796,682	MWh	39.56	mills/kWh	$110,650
Total Generation	$165,839					$165,839
Schedule 85						
Generation Capacity	$57,140	8,157,446	kW	$7.00	per kW demand	$57,140
Generation Energy	$123,289	3,165,188	MWh	38.95	mills/kWh	$123,289
Total Generation	$180,429					$180,429
Schedule 89						
Generation Capacity	$35,658	3,941,686	kW	$9.05	per kW demand	$35,658
Generation Energy	$89,544	2,414,106	MWh	37.09	mills/kWh	$89,544
Total Generation	$125,202					$125,202
Schedule 83, 85, 89 Totals						
Generation Capacity	$147,988	20,504,854	kW	$3.17	per kW demand	$65,000
Secondary		14,967,283	kW	$3.20	per kW demand	$47,895
Primary		5,115,383	kW	$3.09	per kW demand	$15,807
Subtransmission		422,188	kW	$3.05	per kW demand	$1,288
Generation Energy	$323,483	8,375,977	MWh	48.53	mills/kWh	$406,481
Total Generation	$471,470					$471,470
Schedule 83						
Generation Demand Charge		8,405,722	kW	$3.20	per kW demand	$26,898
Generation Energy		2,796,682	MWh	49.68	mills/kWh	$138,941
Total Generation						$165,839
Schedule 85						
Secondary Generation Demand Charge		6,499,505	kW	$3.20	per kW demand	$20,798
Primary Generation Demand Charge		1,657,941	kW	$3.09	per kW demand	$5,123
Generation Energy		3,165,188	MWh	48.81	mills/kWh	$154,508
Total Generation						$180,429
Schedule 89						
Secondary Generation Demand Charge		62,056	kW	$3.20	per kW demand	$199
Primary Generation Demand Charge		3,457,442	kW	$3.09	per kW demand	$10,683
Subtransmission Generation Demand Charge		422,188	kW	$3.05	per kW demand	$1,288
Generation Energy		2,414,106	MWh	46.82	mills/kWh	$113,032
Total Generation						$125,202

PORTLAND GENERAL ELECTRIC
Commercial and Industrial Pricing

	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
Schedule 83						
Generation Demand		8,405,722	kW	$3.20	per kW demand	$26,898
On-peak Energy		1,807,073	MWh	53.22	mills/kWh	$96,172
Off-peak Energy		989,609	MWh	43.22	mills/kWh	$42,771
Total Generation Charges	$165,839					$165,842
Schedule 85						
Secondary Generation Demand		6,499,505	kW	$3.20	per kW demand	$20,798
Primary Generation Demand		1,657,941	kW	$3.09	per kW demand	$5,123
Secondary On-peak Energy		1,625,951	MWh	52.67	mills/kWh	$85,639
Secondary Off-peak Energy		852,690	MWh	42.67	mills/kWh	$36,384
Primary On-peak Energy		430,280	MWh	51.07	mills/kWh	$21,974
Primary Off-peak Energy		256,267	MWh	41.07	mills/kWh	$10,525
Total Generation Charges	$180,429					$180,444
Schedule 89						
Secondary Generation Demand		62,056	kW	$3.20	per kW demand	$199
Primary Generation Demand		3,457,442	kW	$3.09	per kW demand	$10,683
Subtransmission Generation Demand		422,188	kW	$3.05	per kW demand	$1,288
Secondary On-peak Energy		11,096	MWh	52.59	mills/kWh	$584
Secondary Off-peak Energy		7,177	MWh	42.59	mills/kWh	$306
Primary On-peak Energy		1,269,889	MWh	51.06	mills/kWh	$64,841
Primary Off-peak Energy		921,442	MWh	41.06	mills/kWh	$37,834
Subtransmission On-peak Energy		118,841	MWh	50.43	mills/kWh	$5,993
Subtransmission Off-peak Energy		85,660	MWh	40.43	mills/kWh	$3,463
Total Generation Charges	$125,202					$125,190
Schedule 83, 85, 89 Totals	$471,470					$471,476
On/off Peak Delta				10.00		

Demand and Energy Loss Differentials for Selected Schedules

Schedule 85: Secondary/Primary	Losses				
Embedded energy loss differentials	3.380%		1.60	mills/kWh	
Peak demand loss differential	3.548%		$0.11	per kW demand	
Schedule 89	Sec/Prim	Prim/Subtrans			
Embedded energy loss differentials	3.380%	1.450%	1.53	mills/kWh	Sec/Prim
			2.16	mills/kWh	Sec/Subtrans.
Peak demand loss differentials	3.548%	1.540%	$0.11	per kW demand	Sec/Prim
			$0.15	per kW demand	Sec/Subtrans.

PORTLAND GENERAL ELECTRIC
Commercial and Industrial Pricing

	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
Generation Demand						
Schedule 85						
Generation Capacity	$57,140	8,157,446	kW	$7.00	per kW demand	$57,140
Generation Energy	$123,289	3,165,188	MWh	38.95	mills/kWh	$123,289
Total Generation	$180,429					$180,429
Schedule 89						
Generation Capacity	$35,658	3,941,686	kW	$9.05	per kW demand	$35,658
Generation Energy	$89,544	2,414,106	MWh	37.09	mills/kWh	$89,544
Total Generation	$125,202					$125,202
Schedule 85, 89 Totals						
Generation Capacity	$92,798	12,099,132	kW	$3.15	per kW demand	$38,112
Secondary		6,561,561	kW	$3.20	per kW demand	$20,997
Primary		5,115,383	kW	$3.09	per kW demand	$15,807
Subtransmission		422,188	kW	$3.05	per kW demand	$1,288
Generation Energy	$212,833	5,579,294	MWh	47.95	mills/kWh	$267,540
Total Generation	$305,631					$305,631
Schedule 85						
Secondary Generation Demand Charge		6,499,505	kW	$3.20	per kW demand	$20,798
Primary Generation Demand Charge		1,657,941	kW	$3.09	per kW demand	$5,123
Generation Energy		3,165,188	MWh	48.81	mills/kWh	$154,508
Total Generation						$180,429
Schedule 89						
Secondary Generation Demand Charge		62,056	kW	$3.20	per kW demand	$199
Primary Generation Demand Charge		3,457,442	kW	$3.09	per kW demand	$10,683
Subtransmission Generation Demand Charge		422,188	kW	$3.05	per kW demand	$1,288
Generation Energy		2,414,106	MWh	46.82	mills/kWh	$113,032
Total Generation						$125,202

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	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
Schedule 85						
Secondary Generation Demand		6,499,505	kW	$3.20	per kW demand	$20,798
Primary Generation Demand		1,657,941	kW	$3.09	per kW demand	$5,123
Secondary On-peak Energy		1,625,951	MWh	52.67	mills/kWh	$85,639
Secondary Off-peak Energy		852,690	MWh	42.67	mills/kWh	$36,384
Primary On-peak Energy		430,280	MWh	51.07	mills/kWh	$21,974
Primary Off-peak Energy		256,267	MWh	41.07	mills/kWh	$10,525
Total Generation Charges	$180,429					$180,444
Schedule 89						
Secondary Generation Demand		62,056	kW	$3.20	per kW demand	$199
Primary Generation Demand		3,457,442	kW	$3.09	per kW demand	$10,683
Subtransmission Generation Demand		422,188	kW	$3.05	per kW demand	$1,288
Secondary On-peak Energy		11,096	MWh	52.59	mills/kWh	$584
Secondary Off-peak Energy		7,177	MWh	42.59	mills/kWh	$306
Primary On-peak Energy		1,269,889	MWh	51.06	mills/kWh	$64,841
Primary Off-peak Energy		921,442	MWh	41.06	mills/kWh	$37,834
Subtransmission On-peak Energy		118,841	MWh	50.43	mills/kWh	$5,993
Subtransmission Off-peak Energy		85,660	MWh	40.43	mills/kWh	$3,463
Total Generation Charges	$125,202					$125,190
Schedule 85, 89 Totals	$305,631					$305,634
On/off Peak Delta				10.00		

Demand and Energy Loss Differentials for Selected Schedules

			Rate	Unit	
Schedule 85: Secondary/Primary	Losses				
Embedded energy loss differentials	3.380%		1.60	mills/kWh	
Peak demand loss differential	3.548%		$0.11	per kW demand	
Schedule 89	Sec/Prim	Prim/Subtrans			
Embedded energy loss differentials	3.380%	1.450%	1.53	mills/kWh	Sec/Prim
			2.16	mills/kWh	Sec/Subtrans.
Peak demand loss differentials	3.548%	1.540%	$0.11	per kW demand	Sec/Prim
			$0.15	per kW demand	Sec/Subtrans.

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	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
Generation Demand						
Schedule 85						
Generation Capacity	$57,140	8,157,446	kW	$7.00	per kW demand	$57,140
Generation Energy	$123,289	3,165,188	MWh	38.95	mills/kWh	$123,289
Total Generation	$180,429					$180,429
Schedule 89						
Generation Capacity	$35,658	3,941,686	kW	$9.05	per kW demand	$35,658
Generation Energy	$89,544	2,414,106	MWh	37.09	mills/kWh	$89,544
Total Generation	$125,202					$125,202
Schedule 85, 89 Totals						
Generation Capacity	$92,798	12,099,132	kW	$7.67	per kW demand	$92,798
Secondary		6,561,561	kW	$7.79	per kW demand	$51,115
Primary		5,115,383	kW	$7.53	per kW demand	$38,519
Subtransmission		422,188	kW	$7.42	per kW demand	$3,133
Generation Energy	$212,833	5,579,294	MWh	38.15	mills/kWh	$212,865
Total Generation	$305,631					$305,631
Schedule 85						
Secondary Generation Demand Charge		6,499,505	kW	$7.79	per kW demand	$50,631
Primary Generation Demand Charge		1,657,941	kW	$7.53	per kW demand	$12,484
Generation Energy		3,165,188	MWh	38.15	mills/kWh	$120,760
Total Generation	$180,429					$183,876
Schedule 89						
Secondary Generation Demand Charge		62,056	kW	$7.79	per kW demand	$483
Primary Generation Demand Charge		3,457,442	kW	$7.53	per kW demand	$26,035
Subtransmission Generation Demand Charge		422,188	kW	$7.42	per kW demand	$3,133
Generation Energy		2,414,106	MWh	38.15	mills/kWh	$92,105
Total Generation	$125,202					$121,755

PORTLAND GENERAL ELECTRIC
Commercial and Industrial Pricing

	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
Schedule 85/89						
Secondary Generation Demand		6,561,561	kW	$7.79	per kW demand	$51,115
Primary Generation Demand		5,115,383	kW	$7.53	per kW demand	$38,519
Subtransmission Generation Demand		422,188	kW	$7.42	per kW demand	$3,133
Secondary On-peak Energy		1,637,047	MWh	42.67	mills/kWh	$69,853
Secondary Off-peak Energy		859,867	MWh	32.67	mills/kWh	$28,092
Primary On-peak Energy		1,700,169	MWh	41.42	mills/kWh	$70,421
Primary Off-peak Energy		1,177,710	MWh	31.42	mills/kWh	$37,004
Subtransmission On-peak Energy		118,841	MWh	40.91	mills/kWh	$4,862
Subtransmission Off-peak Energy		85,660	MWh	30.91	mills/kWh	$2,648
Total Generation Charges	$305,631					$305,645
On/off Peak Delta				10.00		

Demand and Energy Loss Differentials for Selected Schedules

Schedule 85/89: Secondary/Primary	Losses				
Embedded energy loss differentials	3.380%		1.25	mills/kWh	
Peak demand loss differential	3.548%		$0.26	per kW demand	
Schedule 89	Sec/Prim	Prim/Subtrans			
Embedded energy loss differentials	3.380%	1.450%	1.25	mills/kWh	Sec/Prim
			1.76	mills/kWh	Sec/Subtrans.
Peak demand loss differentials	3.548%	1.540%	$0.26	per kW demand	Sec/Prim
			$0.37	per kW demand	Sec/Subtrans.