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

February 13, 2014

Public Utility Commission of Oregon
Attn: Filing Center
3930 Fairview Industrial Drive SE
P.O. Box 1088
Salem, OR 97308-1088

RE: **Advice No. 14-03, Portland General Electric General Rate Revision UE 283**

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 of Direct Testimony, Exhibits and an Executive Summary, that conform 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 14-043. By April 1st, we will file the remaining power cost updates.

The tariff changes are filed with an effective date of March 18, 2014, 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, 2015.

<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,

Jay Tinker

Jay Tinker
Director, Regulatory Policy & Affairs

Enclosures
cc: Service List – UE 262 (Electronic only)

Advice No. 14-03
Portland General Electric General Rate Revision
Revised Tariff Sheets filed February 13, 2014

Seventh Revision of Sheet No. 7-1
Fifth Revision of Sheet No. 15-1
Sixth Revision of Sheet No. 15-2
Sixth Revision of Sheet No. 15-3
Sixth Revision of Sheet No. 15-4
Fourth Revision of Sheet No. 15-5
Second Revision of Sheet No. 15-6
Sixth Revision of Sheet No. 32-1
Sixth Revision of Sheet No. 32-4
Sixth Revision of Sheet No. 38-1
Eighth Revision of Sheet No. 38-3
Sixth Revision of Sheet No. 47-1
Seventh Revision of Sheet No. 49-1
Ninth Revision of Sheet No. 75-1
Fifth Revision of Sheet No. 75-5
Third Revision of Sheet No. 75-6
Ninth Revision of Sheet No. 76R-1
Fifth Revision of Sheet No. 76R-3
Fifth Revision of Sheet No. 76R-4
Fourth Revision of Sheet No. 76R-5
Sixth Revision of Sheet No. 81-1
Eighth Revision of Sheet No. 83-1
Ninth Revision of Sheet No. 83-2
Fifth Revision of Sheet No. 85-1
Fifth Revision of Sheet No. 85-2
Ninth Revision of Sheet No. 89-1
Ninth Revision of Sheet No. 89-2
First Revision of Sheet No. 90-1
First Revision of Sheet No. 90-2
First Revision of Sheet No. 90-4
Ninth Revision of Sheet No. 91-7
Seventh Revision of Sheet No. 91-9
Sixth Revision of Sheet No. 91-10
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Fifth Revision of Sheet No. 91-12
Fifth Revision of Sheet No. 91-13
Fifth Revision of Sheet No. 91-14
Fifth Revision of Sheet No. 91-15
Seventh Revision of Sheet No. 92-1
Third Revision of Sheet No. 95-3
Fourth Revision of Sheet No. 95-5
Twenty Fifth Revision of Sheet No. 100-1
Sixth Revision of Sheet No. 102-1
Tenth Revision of Sheet No. 122-1
Third Revision of Sheet No. 122-3
Second Revision of Sheet No. 122-4
Sixth Revision of Sheet No. 123-1
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Seventh Revision of Sheet No. 125-1
Fourth Revision of Sheet No. 126-2
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Ninth Revision of Sheet No. 126-4
Sixteenth Revision of Sheet No. 128-1
Fifteenth Revision of Sheet No. 128-2
Twenty Revision of Sheet No. 128-4
Original Sheet No. 143-1
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Sixth Revision of Sheet No. 485-3
Third Revision of Sheet No. 485-4
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Fifth Revision of Sheet No. 532-1
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Ninth Revision of Sheet No. 575-1
Ninth Revision of Sheet No. 576R-1
Seventh Revision of Sheet No. 583-1
Fourth Revision of Sheet No. 585-1
Ninth Revision of Sheet No. 589-1
First Revision of Sheet No. 590-1
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Eleventh Revision of Sheet No. 591-6
Eleventh Revision of Sheet No. 591-7
Seventh Revision of Sheet No. 591-8
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Fourth Revision of Sheet No. 591-11
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Third Revision of Sheet No. 595-3
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First Revision of Sheet No. 750-1
First Revision of Sheet No. 750-2
First Revision of Sheet No. 750-3

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	$11.00		(I)
Three Phase Service	$11.00		(I)
Transmission and Related Services Charge	0.254	¢ per kWh	(R)
Distribution Charge	4.025	¢ per kWh	(I)
Energy Charge Options			
Standard Service			
First 1,000 kWh	6.127	¢ per kWh	(R)
Over 1,000 kWh	6.849	¢ per kWh	
or			
Time-of-Use (TOU) Portfolio (Whole Premises or Electric Vehicle (EV) TOU) (Enrollment is necessary)			
On-Peak Period	11.933	¢ per kWh	
Mid-Peak Period	6.849	¢ per kWh	
Off-Peak Period	3.979	¢ per kWh	
First 1,000 kWh block adjustment**	(0.722)	¢ per kWh	(R)

* 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	0.176	¢ per kWh	**(R)**
Distribution Charge	4.781	¢ per kWh	**(I)**
Cost of Service Energy Charge	4.966	¢ 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	$12.57 [2]	(R)
	400	21,000	147	21.00 [2]	(I)
	1,000	55,000	374	44.18 [2]	(I)
HPS	70	6,300	30	9.11 [2]	(R)
	100	9,500	43	10.34	(R)
	150	16,000	62	12.25	(R)
	200	22,000	79	14.25	(I)
	250	29,000	102	16.50	(R)
	310	37,000	124	19.08[2]	(R)
	400	50,000	163	22.96	(I)
Flood, HPS	100	9,500	43	10.38[2]	(R)
	200	22,000	79	14.94[2]	
	250	29,000	102	17.24	
	400	50,000	163	23.29	
Shoebox, HPS (bronze color, flat lens or drop lens, multi-volt)	70	6,300	30	10.46	
	100	9,500	43	11.94	
	150	16,500	62	14.08	
Special Acorn Type, HPS	100	9,500	43	14.80	
HADCO Victorian, HPS	150	16,500	62	16.58	
	200	22,000	79	18.99	
	250	29,000	102	21.32	
Early American Post-Top, HPS Black	100	9,500	43	11.10	(R)

(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	$12.68	(R)
	175	12,000	71	14.01	
Flood, Metal Halide	350	30,000	139	22.23	
	400	40,000	156	22.80	
Flood, HPS	750	105,000	285	38.33	
HADCO Independence, HPS	100	9,500	43	14.80	
	150	16,000	62	16.39	
HADCO Capitol Acorn, HPS	100	9,500	43	18.52	
	150	16,000	62	20.34	
	200	22,000	79	22.01	
	250	29,000	102	24.31	
HADCO Techtra, HPS	100	9,500	43	23.47	
	150	16,000	62	24.86	
	250	29,000	102	28.22	
HADCO Westbrooke, HPS	70	6,300	30	16.25	
	100	9,500	43	17.31	
	150	16,000	62	19.20	
	200	22,000	79	21.15	
	250	29,000	102	23.28	
KIM Archetype, HPS	250	29,000	102	26.11	
	400	50,000	163	27.33	
Holophane Mongoose, HPS	150	16,000	62	17.03	
	250	29,000	102	20.35	(R)

(1) See Schedule 100 for applicable adjustments.

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)
Rates for LED Area Lighting

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate Per Luminaire[1]	
Acorn					
LED	60	5,488	21	$14.72	(R)
	70	4,332	24	16.86	
Cobrahead Equivalent					
LED	37	2,530	13	5.06	
	50	3,162	17	5.46	
	52	3,757	18	5.95	
	67	5,050	23	6.71	
	106	7,444	36	8.82	
Westbrooke LED (Non-Flare)	49	5,094	17	19.00	
	69	6,680	24	20.44	
	109	8,176	37	21.99	
	136	12,728	46	26.45	
	206	18,159	70	28.84	
Westbrooke LED (Flare)	49	5,094	17	21.07	
	69	6,680	24	22.10	
	109	8,176	37	24.04	
	136	12,728	46	27.73	
	206	18,159	70	30.12	(R)
CREE XSP LED	25	2,529	9	3.70	(I)
	42	3,819	14	4.30	(R)
	48	4,373	16	4.97	
	56	5,863	19	5.78	
	91	8,747	31	6.97	(R)

(1) See Schedule 100 for applicable adjustments.

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	$7.03	(R)
	40 to 55	9.20	
Wood, Painted for Underground	35 or less	7.03 [2]	
Wood, Curved Laminated	30 or less	8.71 [2]	
Aluminum, Regular	16	8.39	
	25	13.93	
	30	15.05	
	35	18.00	
Aluminum, Fluted Ornamental	14	12.29	
Aluminum Davit	25	12.88	
	30	13.83	
	35	15.12	
	40	20.52	
Aluminum Double Davit	30	20.42	
Aluminum, HADCO, Fluted Ornamental	16	12.56	(R)
Aluminum, HADCO, Non-fluted Techtra Ornamental	18	24.18	
Aluminum, HADCO, Fluted Westbrooke	18	25.44	(I)
Aluminum, HADCO, Non-Fluted Westbrooke	18	26.97	(I)
Concrete Ameron Post-Top	25	24.12	(R)

(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	
Fiberglass Fluted Ornamental; Black	14	14.86	(R)
Fiberglass, Regular			
Black	20	6.18	
Gray or Bronze	30	10.50	
Other Colors (as available)	35	9.04	
Fiberglass, Anchor Base Gray	35	16.51	
Fiberglass, Direct Bury with Shroud	18	9.96	(R)

INSTALLATION CHARGE

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

ADJUSTMENTS

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

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

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			(I)
Single Phase Service	$15.00		(I)
Three Phase Service	$20.00		
Transmission and Related Services Charge	0.222	¢ per kWh	(R)
Distribution Charge			
First 5,000 kWh	3.983	¢ per kWh	(I)
Over 5,000 kWh	1.027	¢ per kWh	(I)
Energy Charge Options			
Standard Service	5.825	¢ per kWh	(R)
or			
Time-of-Use (TOU) Portfolio (enrollment is necessary)			
On-Peak Period	10.251	¢ per kWh	
Mid-Peak Period	5.825	¢ per kWh	
Off-Peak Period	3.419	¢ 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 Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index)
- plus 0.302 ¢ per kWh for wheeling **(I)**
- times a loss adjustment factor of 1.0685 **(R)**

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, 2015. **(C)**

MONTHLY RATE

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

Basic Charge			
Single Phase Service	$25.00		
Three Phase Service	$25.00		
Transmission and Related Services Charge	0.210	¢ per kWh	**(R)**
Distribution Charge	6.657	¢ per kWh	**(I)**
Energy Charge*			
On-Peak Period	6.288	¢ per kWh	**(R)**
Off-Peak Period	5.288	¢ per kWh	**(R)**

* 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 Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.302¢ 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 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:

Secondary Delivery Voltage 1.0685 **(R)**

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**	$35.00		(I)
Winter Months**	No Charge		
Transmission and Related Services Charge	0.342	¢ per kWh	
Distribution Charge			
First 50 kWh per kW of Demand***	8.232	¢ per kWh	
Over 50 kWh per kW of Demand	6.232	¢ per kWh	
Energy Charge	7.246	¢ 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**	$40.00		**(I)**
Winter Months**	No Charge		
Transmission and Related Services Charge	0.310	¢ per kWh	**(R)**
Distribution Charge			
First 50 kWh per kW of Demand***	6.147	¢ per kWh	**(I)**
Over 50 kWh per kW of Demand	4.147	¢ per kWh	
Energy Charge	6.866	¢ 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	$5,440.00	$4,870.00	$5,600.00	**(I)**
Transmission and Related Services Charge				
per kW of monthly On-Peak Demand	$0.84	$0.82	$0.81	**(R)**
Distribution Charges				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.97	$1.94	$1.94	**(I)**
Over 4,000 kW	$1.50	$1.47	$1.47	**(I)**
per kW of monthly On-Peak Demand	$2.24	$2.20	$0.83	**(I)(R)**
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	0.085` ¢	0.082 ¢	0.080 ¢	**(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 Powerdex Mid-Columbia Hourly Firm Electricity Price Index (Powerdex-Mid-C Hourly Firm Index) plus 0.302¢ per kWh for wheeling, a 0.300¢ per kWh recovery **(I)**
factor, plus losses.

SCHEDULE 75 (Continued)

ENERGY CHARGE (Continued)

Unscheduled Energy (Continued)

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.

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.

The Company may request that a Customer taking Unscheduled Energy during more than 1,000 hours during a calendar year provide information detailing the reasons that the generator was not able to run during those hours in order to determine the appropriate Baseline Demand.

LOSSES

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

Subtransmission Delivery Voltage	1.0356	**(I)**
Primary Delivery Voltage	1.0496	**(I)**
Secondary Delivery Voltage	1.0685	**(R)**

DIRECT ACCESS PARTIAL REQUIREMENTS SERVICE

A Customer served under this schedule may elect to receive Direct Access Partial Requirements Service from an Electricity Service Supplier (ESS) under the terms of Schedule 575 provided it has given notice consistent with any Baseline Energy option requirements. A Customer may return to Schedule 75 provided it has met any term requirements of Schedule 575 and any requirements needed to purchase Baseline Energy if needed.

MINIMUM CHARGE

The Minimum Charge will be the Basic, Transmission, Distribution, Demand and Generation Contingency Reserves Charges, when applicable. In addition, the Company may require a higher Minimum Charge, if necessary, to justify the Company's investment in service Facilities.

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 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	$0.033	$0.032	$0.032	**(R)**
Daily ERP Demand Charge per kW of Daily ERP Demand during On-Peak hours per day**	$0.087	$0.086	$0.032	**(I)(R)** **(D)**
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 Powerdex Mid-Columbia Hourly Price Index (Powerdex-Mid-C Hourly Index) plus a 5% adder, which will not be less than 0.15¢ per kWh, plus 0.302¢ per kWh for wheeling, **(I)** 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.

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 0.302¢ per kWh for wheeling, plus **(I)** 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.

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¢ **(I)** per kWh, plus 0.302¢ 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.

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	1.0356	**(I)**
Primary Delivery Voltage	1.0496	**(I)**
Secondary Delivery Voltage	1.0685	**(R)**

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 Powerdex Mid-Columbia Hourly Price Index (Powerdex-Mid-C Hourly Index), plus 0.302¢ 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 Powerdex-Mid-C Hourly Index plus 0.302¢ 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 Powerdex Mid-Columbia Hourly Price Index (Powerdex-Mid-C Hourly Index), plus 10%, plus 0.302¢ per kWh for wheeling, plus losses. **(I)**

For negative excess Imbalance Energy, the excess Energy Imbalance is multiplied by the Settlement Price of the Powerdex-Mid-C Hourly Index, less 10%, plus 0.302¢ 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 Intercontinental Exchange Mid-Columbia Daily on- and off-peak Firm Electricity Price Index (ICE-Mid-C Firm Index) plus 0.302¢ per kWh **(I)** 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.

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	1.0356	**(I)**
Primary Delivery Voltage	1.0496	**(I)**
Secondary Delivery Voltage	1.0685	**(R)**

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 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. 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	
Three Phase Service	$40.00	
Transmission and Related Services Charge		
per kW of monthly On-Peak Demand	$0.84	(R)
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 30 kW	$2.96	(I)
Over 30 kW	$2.86	|
per kW of monthly On-Peak Demand	$2.24	(I)
Energy Charge ***		
On-Peak Period***	6.159 ¢	(R)
Off-Peak Period***	5.159 ¢	|
See below for Daily Pricing Option description.		|
System Usage Charge		|
per kWh	0.672 ¢	(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 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 Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.302¢ 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:

Secondary Delivery Voltage 1.0685 **(R)**

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)

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 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 Demand 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.

MONTHLY RATE

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

	Delivery Voltage		
	Secondary	Primary	
Basic Charge	$470.00	$500.00	(R)
Transmission and Related Services Charge			
per kW of monthly On-Peak Demand	$0.84	$0.82	(R)
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 200 kW	$3.09	$3.04	(I)
Over 200 kW	$2.19	$2.14	
per kW of monthly On-Peak Demand	$2.24	$2.20	(I)
Energy Charge			
On-Peak Period***	5.985 ¢	5.881 ¢	(R)
Off-Peak Period***	4.985 ¢	4.881 ¢	
See below for Daily Pricing Option description.			
System Usage Charge			
per kWh	0.114 ¢	0.110 ¢	(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 Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.302¢ 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	1.0496	**(I)**
Secondary Delivery Voltage	1.0685	**(R)**

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
(>4,000 kW)

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.

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	$5,440.00	$4,870.00	$5,600.00	(I)
Transmission and Related Services Charge				
per kW of monthly On-Peak Demand	$0.84	$0.82	$0.81	(R)
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.97	$1.94	$1.94	(I)
Over 4,000 kW	$1.50	$1.47	$1.47	(I)
per kW of monthly On-Peak Demand	$2.24	$2.20	$0.83	(I)(R)
Energy Charge				(R)
On-Peak Period***	5.725 ¢	5.629 ¢	5.557 ¢	
Off-Peak Period***	4.725¢	4.629 ¢	4.557 ¢	
See below for Daily Pricing Option description.				
System Usage Charge				
Per kWh	0.085 ¢	0.082 ¢	0.080 ¢	(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 Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.302¢ 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:

Subtransmission Delivery Voltage	1.0356	**(I)**
Primary Delivery Voltage	1.0496	**(I)**
Secondary Delivery Voltage	1.0685	**(R)**

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 90
LARGE NONRESIDENTIAL
STANDARD SERVICE
(>4,000 kW and Aggregate to >100 MWa)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer who meet the following conditions: 1) Individual account 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 2) where combined usage of all accounts meeting condition 1 for the Large Nonresidential Customer aggregate to at least 100 MWa in a calendar year; and 3) the customer maintains a load factor of 80% or greater for each account.

MONTHLY RATE

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

Basic Charge	$25,000.00	**(I)**
Transmission and Related Services Charge		
per kW of monthly On-Peak Demand	$0.82	**(R)**
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 4,000 kW	$1.08	**(R)**
Over 4,000 kW	$1.08	**(R)**
per kW of monthly On-Peak Demand	$2.20	**(I)**
Energy Charge		
On-Peak Period***	5.488 ¢	**(R)**
Off-Peak Period***	4.488 ¢	
See below for Daily Pricing Option description.		
System Usage Charge		
Per kWh	0.071 ¢	**(R)(C)**

* 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 90 (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 Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.302¢ 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:

Subtransmission Delivery Voltage	1.0356	**(I)**
Primary Delivery Voltage	1.0496	**(I)**
Secondary Delivery Voltage	1.0685	**(R)**

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 90 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 90 (Concluded)

ADJUSTMENTS

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

(D)

TERM

Service will be for not less than one year or as otherwise provided under this Schedule.

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	0.176 ¢ per kWh	**(R)**
Distribution Charge	4.781 ¢ per kWh	**(I)**
Energy Charge		
Cost of Service Option	4.966 ¢ 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 Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.302¢ 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 1.0685. **(R)**

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	*	$ 1.36	(I)
	100	9,500	43	*	1.38	
	150	16,000	62	*	1.38	
	200	22,000	79	*	1.44	
	250	29,000	102	*	1.46	
	400	50,000	163	*	1.47	
Cobrahead	70	6,300	30	$ 5.05	1.61	(R)
	100	9,500	43	4.99	1.60	
	150	16,000	62	5.02	1.61	(R)
	200	22,000	79	5.76	1.68	(I)
	250	29,000	102	5.73	1.68	(R)
	400	50,000	163	6.14	1.73	
Flood	250	29,000	102	6.47	1.77	
	400	50,000	163	6.47	1.77	
Early American Post-Top	100	9,500	43	5.75	1.69	
Shoebox (bronze color, flat lens, or drop lens, multi-volt)	70	6,300	30	6.40	1.78	
	100	9,500	43	6.59	1.80	
	150	16,000	62	6.85	1.84	(I)

* 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	$6.18	$ 0.14	
Fiberglass, Bronze	30	9.74	0.22	(I)
Fiberglass, Gray	30	10.50	0.24	
Wood, Standard	30 to 35	7.03	0.16	
Wood, Standard	40 to 55	9.20	0.21	(R)(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	$ 9.88	$ 2.17	(R)(I)
HADCO Victorian, HPS	150	16,000	62	9.78	2.17	
	200	22,000	79	10.50	2.29	
	250	29,000	102	10.55	2.29	
HADCO Capitol Acorn, HPS	100	9,500	43	13.60	2.63	
	150	16,000	62	13.54	2.67	
	200	22,000	79	13.52	2.66	
	250	29,000	102	13.54	2.67	
Special Architectural Types						
HADCO Independence, HPS	100	9,500	43	9.88	2.15	
	150	16,000	62	9.59	2.13	
HADCO Techtra, HPS	100	9,500	43	18.55	3.23	
	150	16,000	62	18.06	3.18	
	250	29,000	102	17.45	3.14	
HADCO Westbrooke, HPS	70	6,300	30	12.62	2.50	
	100	9,500	43	12.39	2.47	
	150	16,000	62	12.40	2.48	
	200	22,000	79	12.66	2.54	
	250	29,000	102	12.51	2.53	(R)(I)

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	$ 5.65	$ 1.94	(R)(I)
Flood, Metal Halide	350	30,000	139	7.79	2.22	
Flood, HPS	750	105,000	285	9.40	2.71	
Holophane Mongoose, HPS	150	16,000	62	10.23	2.22	
	250	29,000	102	9.58	2.16	(R)(I)
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	$8.39	$ 0.19	(R)(I)
	25	13.93	0.31	
	30	15.05	0.34	(I)
	35	18.00	0.40	
Aluminum Davit	25	13.90	0.31	
	30	13.83	0.31	(I)
	35	15.12	0.34	
	40	20.52	0.46	
Aluminum Double Davit	30	20.42	0.46	(R)(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	$12.29	$ 0.28	(R)(I)
Aluminum, HADCO, Non-Fluted Techtra Ornamental	18	24.18	0.54	(I)
Aluminum, HADCO, Fluted Ornamental	16	12.56	0.28	
Aluminum, HADCO, Non-Fluted Ornamental	16	25.69	0.58	(I)
Aluminum, HADCO, Fluted Westbrooke	18	24.24	0.54	
Aluminum, HADCO, Non-Fluted Westbrooke	18	25.69	0.58	
Aluminum, Painted Ornamental	35	41.28	0.92	
Concrete. Decorative Ameron	20	24.12	0.54	
Concrete, Ameron Post-Top	25	24.12	0.54	(I)
Fiberglass, HADCO, Fluted Ornamental Black	14	14.86	0.33	
Fiberglass, Smooth	18	6.16	0.14	
Fiberglass, Regular				
color may vary	22	5.51	0.12	
	35	9.04	0.20	
Fiberglass, Anchor Base, Gray	35	16.51	0.37	(I)
Fiberglass, Direct Bury with Shroud	18	9.96	0.22	(R)

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	$ 4.94	$ 1.55	(R)(I)
	250	10,000	94	*	*	
	400	21,000	147	5.76	1.68	
	1,000	55,000	374	6.42	2.01	(R)
Special Box Similar to GE "Space-Glo"						
HPS	70	6,300	30	6.49	1.70	
Mercury Vapor	175	7,000	66	6.44	1.65	(R)(I)

* 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	*	$ 2.06	(I)
	150	16,000	62	*	2.08	(I)
	250	29,000	102	*	*	
	400	50,000	163	*	*	
Metal Halide	250	20,500	99	*	1.28	(I)
	400	40,000	156	*	1.28	
Cobrahead, Metal Halide	175	12,000	71	$ 5.88	1.77	(R)
Flood, Metal Halide	400	40,000	156	6.67	1.81	(R)
Cobrahead, Dual Wattage, HPS						
70/100 Watt Ballast	100	9,500	43	*	1.61	
100/150 Watt Ballast	100	9,500	43	*	1.61	
100/150 Watt Ballast	150	16,000	62	*	1.63	
Special Architectural Types Including Philips QL Induction Lamp Systems						
HADCO Victorian, QL	85	6,000	32	*	0.77	
	165	12,000	60	*	1.04	
HADCO Techtra, QL	165	12,000	60	21.86	1.23	(R)
Special Architectural Types						
KIM SBC Shoebox, HPS	150	16,000	62	*	2.64	
KIM Archetype, HPS	250	29,000	102	*	2.87	
	400	50,000	163	*	2.27	
Special Acorn-Type, HPS	70	6,300	30	9.85	2.14	(R)(I)
Special GardCo Bronze Alloy						
HPS	70	5,000	30	*	*	
Mercury Vapor	175	7,000	66	*	*	
Special Acrylic Sphere						
Mercury Vapor	400	21,000	147	*	*	

* 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	$ 5.64	$ 1.58	(R)(I)
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	5.65	1.59	(R)(I)
Flood, HPS	70	6,300	30	4.87	1.48	(R)
	100	9,500	43	5.03	1.60	(I)
	200	22,000	79	6.45	1.75	
Cobrahead, HPS						
Power Door	310	37,000	124	6.13	2.08	(R)(I)
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.

SCHEDULE 91 (Continued)

RATES FOR OBSOLETE LIGHTING POLES

Type of Pole	Poles Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Aluminum Post	30	$ 8.39	*	(R)
Bronze Alloy GardCo	12	*	$ 0.17	
Concrete, Ornamental	35 or less	13.93	0.31	(R)
Steel, Painted Regular **	25	13.93	0.31	
Steel, Painted Regular **	30	15.05	0.34	(R)(I)
Steel, Unpainted 6-foot Mast Arm **	30	*	0.31	
Steel, Unpainted 6-foot Davit Arm **	30	*	0.31	
Steel, Unpainted 8-foot Mast Arm **	35	*	0.34	
Steel, Unpainted 8-foot Davit Arm **	35	*	0.34	(I)
Wood, Laminated without Mast Arm	20	6.18	0.14	(R)
Wood, Laminated Street Light Only	20	6.18	*	
Wood, Curved Laminated	30	9.74	0.22	(I)
Wood, Painted Underground	35	7.03	0.16	(I)
Wood, Painted Street Light Only	35	7.03	*	(R)

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

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 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	0.175	¢ per kWh	**(R)**
Distribution Charge	2.110	¢ per kWh	**(I)**
Energy Charge	5.194	¢ 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 (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	0.176 ¢ per kWh	**(R)**
Distribution Charge	4.781 ¢ per kWh	**(I)**
Energy Charge		
Cost of Service Option	4.966 ¢ 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 Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.302¢ 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 1.0685. **(R)**

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
	$122.00 per hour	$163.00 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	
Cobrahead Equivalent	37	2,530	13	$ 3.36	(R)
Cobrahead Equivalent	50	3,162	17	3.36	
Cobrahead Equivalent	52	3,757	18	3.75	
Cobrahead Equivalent	67	5,050	23	4.18	
Cobrahead Equivalent	106	7,444	36	4.99	

RATES FOR DECORATIVE LIGHTING

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rate Option A	
Acorn LED	60	5,488	21	$12.19	
	70	4,332	24	14.07	
Westbrooke (Non-Flared)	49	5,094	17	16.97	
LED	69	6,680	24	17.74	
	109	8,176	37	18.01	
	136	12,728	46	21.66	
	206	18,159	70	21.66	
Westbrooke (Flared)	49	5,094	17	19.09	
LED	69	6,680	24	19.44	
	109	8,176	37	20.10	
	136	12,728	46	22.97	
	206	18,159	70	22.97	(R)

SCHEDULE 100
SUMMARY OF APPLICABLE ADJUSTMENTS

The following summarizes the applicability of the Company's adjustment schedules.

(N)

Schs.	102 (1)	105	106 (1)	108 (3)	109 (1)	110 (1)	115	122	123 (1)	125 (1)	126	128 (4)	129 (1)	135	137	142	143	144	145
7	x	x	x	x	x	x	x	x	x	x	x			x	x	x	x	x	x
12	x	x	x	x	x	x	x	x	x	x	x			x	x	x	x	x	x
15	x	x	x	x	x	x	x	x	x	x	x			x	x	x	x	x	x
32	x	x	x	x	x	x	x	x	x	x	x	x		x	x	x	x	x	x
38	x	x	x	x	x	x	x	x	x	x	x	x		x	x	x	x	x	x
47	x	x	x	x	x	x	x	x	x	x	x			x	x	x	x	x	x
49	x	x	x	x	x	x	x	x	x	x	x			x	x	x	x	x	x
75	x[2]	x[2]	x	x	x[2]	x[2]	x	x[2]	x	x[2]	x[2]	x		x	x	x	x	x	x
76R	x		x	x			x									x			
83	x	x	x	x	x	x	x	x	x	x	x	x		x	x	x	x	x	x
85	x	x	x	x	x	x	x	x	x	x	x	x		x	x	x	x	x	x
89	x	x	x	x	x	x	x	x	x	x	x	x		x	x	x	x	x	x
90	x	x	x	x	x	x	x	x	x	x	x	x		x	x	x	x	x	x
91		x	x	x	x	x	x	x	x	x	x	x		x	x	x	x	x	x
92		x	x	x	x	x	x	x	x	x	x			x	x	x	x	x	x
95		x	x	x	x	x	x	x	x	x	x	x		x	x	x	x	x	x
485	x	x	x	x	x	x	x		x		x[5]		x			x	x	x	
489	x	x	x	x	x	x	x		x		x[5]		x			x	x	x	
490	x	x	x	x	x	x	x		x		x		x			x	x	x	
491		x	x	x	x	x	x		x		x		x			x	x	x	
492		x	x	x	x	x	x		x		x		x			x	x	x	
495		x	x	x	x	x	x		x		x		x			x	x	x	
515	x	x	x	x	x	x	x		x		x[5]	x			x	x	x	x	x
532	x	x	x	x	x	x	x		x		x[5]	x			x	x	x	x	x
538	x	x	x	x	x	x	x		x		x[5]	x			x	x	x	x	x
549	x	x	x	x	x	x	x		x		x[5]	x			x	x	x	x	x
575	x[2]	x[2]	x	x	x	x	x		x		x[2]	x			x	x	x	x	x
576R	x		x	x			x									x			
583	x	x	x	x	x	x	x		x		x[5]	x			x	x	x	x	x
585	x	x	x	x	x	x	x		x		x[5]	x			x	x	x	x	x
589	x	x	x	x	x	x	x		x		x[5]	x			x	x	x	x	x
590	x	x	x	x	x	x	x		x		x	x			x	x	x	x	x
591		x	x	x	x	x	x		x		x[5]	x			x	x	x	x	x
592		x	x	x	x	x	x		x		x[5]	x			x	x	x	x	x
595		x	x	x	x	x	x		x		x[5]	x			x	x	x	x	x

(C)

(C)

(N)

(1) Where applicable.
(2) These adjustments are applicable only to the Baseline and Scheduled Maintenance Energy.
(3) Schedule 108 applies to the sum of all charges less taxes, Schedule 109 and 115 charges and one-time charges such as deposits.
(4) Applicable to Nonresidential Customer who receive service at Daily pricing (other than Cost of Service) or Direct Access (excluding service on Schedules 485, 489, 490, 491, 492 and 495).
(5) Not applicable to Customers where service was received for the entire calendar year that the Annual Power Cost Variance accrued.

SCHEDULE 102
REGIONAL POWER ACT EXCHANGE* CREDIT

PURPOSE

Each Customer's bill rendered under schedules providing Residential Service, Farm Service and Nonresidential Farm Irrigation and Drainage Pumping Service will include the Regional Power Act Exchange Credit applied to each kWh sold when the Customer qualifies for the adjustment according to the definitions and limitations set forth in this schedule. Where Customers are served by Electricity Service Suppliers (ESSs), the ESS will agree to pass through the credit to the Customer.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all bills for Direct Access Service, Emergency Default Service, Standard Service and Residential Service where the Customer meets the definition of Residential Service, Farm Service or Farm Irrigation and Drainage Pumping Service as specified in this schedule.

REGIONAL POWER ACT EXHANGE CREDIT

The credit will be the value of power and other benefits inclusive provided in accordance with the terms of the Settlement Agreement between the Company and the Bonneville Power Administration (BPA).

The credit inclusive of interest is:

Schedule 7				
	First 1,000 kWh	0.889	¢ per kWh	**(R)**
	Over 1,000 kWh	0.000	¢ per kWh	
All other schedules		0.730	¢ per kWh	**(R)**

RESIDENTIAL SERVICE

Residential Service means Electricity Service provided for residential purposes including service to master-metered apartments, apartment utility rooms, common areas, and other residential uses.

* Short title for "Pacific Northwest Electric Power Planning and Conservation Act".

SCHEDULE 122
RENEWABLE RESOURCES AUTOMATIC ADJUSTMENT CLAUSE

PURPOSE

This Schedule recovers the revenue requirements of qualifying Company-owned or contracted new renewable energy resource projects (including associated transmission) not otherwise included in rates. Additional new renewable projects may be incorporated into this schedule as they are placed in service. This Schedule also recovers or refunds differences between the projected costs of qualifying renewable resources made in a ratemaking process and the actual costs incurred. This adjustment schedule is implemented as an automatic adjustment clause as provided for under ORS 757.210 and Section 13 of the Oregon Renewable Energy Act (OREA). (C) | (C)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all bills for Electricity Service except Schedules 76, 485, 489, 490, 491, 492, 495 and 576. This schedule is not applicable to direct access customers after December 31, 2010.

ADJUSTMENT RATE

The Adjustment Rate, applicable for service on and after the effective date of this schedule are:

Schedule		
7	0.000	¢ per kWh
15	0.000	¢ per kWh
32	0.000	¢ per kWh
38	0.000	¢ per kWh
47	0.000	¢ per kWh
49	0.000	¢ per kWh
75		
Secondary	0.000	¢ per kWh
Primary	0.000	¢ per kWh
Subtransmission	0.000	¢ per kWh
83	0.000	¢ per kWh
85		
Secondary	0.000	¢ per kWh
Primary	0.000	¢ per kWh

SCHEDULE 122 (Continued)

QUALIFYING RESOURCE COST VARIANCE TRUE-UP **(N)**

Annually, the variances between the costs projected in either a general rate-making process or through the Schedule 125 Annual Power Cost Update and the actual costs of qualifying renewable resources will be calculated and subject to collection or refund through this Schedule. The calculation of these collections or refunds will be based upon the variances in energy output value, production tax credits, integration costs, and royalties for RPS-compliant resources. For qualifying resources owned by PGE, the cost variance will be calculated by comparing the projections made of the hourly generation, hourly prices, monthly royalty payments, and monthly integration costs to the actual hourly generation, the actual hourly prices as reported by the PowerDex Mid-Columbia Hourly Price Index, the actual monthly royalty payments, and the actual integration costs. For contracted qualifying resources, the variance will be calculated by comparing the projections made of the monthly generation and contract prices to the actual monthly generation and contract price. The filing for these collections or refunds will occur at the same time as the filing for the Schedule 126 Annual Power Cost Variance Mechanism. **(N)**

TIME AND MANNER OF FILING

For each calendar year that the Company is required to update the Renewable Resource Annual Revenue Requirements or proposes to include a new resource under this schedule, the Company will file by no later than April 1, the following:

1. Revised rates under this schedule and a transmittal letter that summarizes the proposed revenue requirements and charges for both the new resource(s) and the updated revenue requirements and charges for applicable resources previously approved for recovery under this schedule. In addition, the filing will include revised income taxes and associated ratios to calculate “taxes authorized to be collected in rates” under ORS 757.268.

2. Within the Company’s Annual Power Cost Update (Schedule 125) filing, the Company will include for the following year the expected generation of resources included in this schedule and the power costs of these resources.

3. Work papers that support the calculation of revenue requirements for all applicable resources and demonstrate how the proposed prices are calculated.

By December 1, the Company will file the updated rates that are in compliance with the Commission’s findings in the proceeding reviewing the April 1 filing.

(M)

SCHEDULE 122 (Concluded)

SPECIAL CONDITIONS (T)

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. (M)

2. Each renewable resource project (and associated transmission) included in this adjustment schedule must be separately identified and be a new resource defined as "renewable" in the OREA.

3. The costs for projects included under this schedule will be updated annually as provided above, and will continue to be recovered under Schedule 122 until such time as the costs are included in base rates or the project is no longer in service.

4. The in-service date for the new renewable resource project or each separately identifiable project segment will be verified by an attestation from the Company stating that the specific renewable resource project, or project segment, has met requirements for being commercially operational and is in service. (M)

   If the actual costs of an eligible resource cannot be verified by the final round of testimony in the proceeding reviewing the April 1 filing, the Company will include in its December 1 compliance filing an update to reflect then-current actual resource costs, or forecasted costs where appropriate. If the updated costs are lower than the projected costs in the record of the proceeding, the update will contain sufficient information to support a reduction in the proposed adjustment charges before the January 1 effective date. If updated costs are higher than the projected costs in the record or if actual costs cannot be verified until after December 1, the Company may file for deferred accounting under the OREA to allow an opportunity for recovery of the cost differences between the projected costs in the record and the prudently incurred actual costs. (T) (D)

5. For Schedule 122 filings made on and after April 2009, the Commission may condition approval of a proposed change in Schedule 122 charges on PGE making a filing under ORS 757.210 within six months after the Commission order approving the proposed change. Through this filing, the Company will roll into the generation component of its rates all of the costs, or a portion thereof identified by the Commission, that are being collected through the then existing Schedule 122 charges. The Commission's order for conditional approval must be based upon: (1) a finding that the costs, or a portion thereof, specified by the Commission have been collected through Schedule 122 for a reasonable period of years, as determined by the Commission; or (2) for good cause, as determined by the Commission. (T)

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 6.659 cents/kWh for Schedule 7 **(I)** and 6.082 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 $55.96 per month for Schedule 7 and $88.17 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. For Schedule 7, a Secondary Fixed Charge equal to 75% of the Monthly Fixed **(C)** Charge will be used to calculate Fixed Charge Revenues for actual customer counts that exceed the projected customer counts used to establish base rates in a general rate review. The Schedule 7 Secondary Fixed Charge is $41.97. **(I)**

SCHEDULE 123 (Continued)

SALES NORMALIZATION ADJUSTMENT (SNA) (Continued)

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.

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.

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 4.489 **(I)**
cents per kWh.

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, 90, 91, 92, and 95. Customers served under the daily price option contained in schedules 32, 38, 75, 81, 83, 85, 89, 90, 91, and 95 are exempt from Schedule 125.

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.

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.
- Costs associated with wind integration.
- Forward market prices for both gas and electricity.
- Projected loads.
- Contracts for the purchase or sale of power and fuel.
- Emission control chemical costs.
- Thermal plant variable operation and maintenance, including the cost of transmission losses, for dispatch purposes.
- Changes in hedges, options, and other financial instruments used to serve retail load.
- Transportation contracts and other fixed transportation costs.
- Reciprocating engine lubrication oil costs. (C)
- No other changes or updates will be made in the annual filings under this schedule.

Schedule 126 (Continued)

DEFINITIONS

Actual Loads

Actual loads are total annual calendar retail loads adjusted to exclude loads of Customers to whom this adjustment schedule does not apply.

Actual NVPC

Incurred cost of power based on the definition for NVPC described here in. Actual NVPC will be increased by 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. Actual NVPC will be reduced by the **(C)**
costs associated with qualifying renewable resources. **(C)**

Actual Unit NVPC

The Actual Unit NVPC is the Actual NVPC divided by Actual Loads.

Annual Variance (AV)

The Annual Variance (AV) is the dollar amount calculated annually based on the following formula:

(Actual Unit NVPC – Adjusted Base Unit NVPC) * Actual Loads

Base Unit NVPC

The Base Unit NVPC is the NVPC used to develop rate schedules for the applicable year divided by the associated calendar basis retail loads. Base NVPC are updated annually in accordance with Schedule 125. Base Unit NVPC will be reduced by the projected costs of **(C)**
qualifying renewable resources. **(C)**

Adjusted Base Unit NVPC

The Adjusted Base Unit NVPC is the NVPC used to calculate the Annual Variance. The Adjusted Base Unit NVPC is the Base Unit NVPC (determined in accordance with Schedule 125) adjusted for load and cost changes resulting from non-residential customers choosing service under Schedule 515 through 595 after the November update for the applicable year.

Negative Annual Power Cost Deadband

The Negative Annual Power Cost Deadband is ($15.0 million).

Positive Annual Power Cost Deadband

The Positive Annual Power Cost Deadband is $30.0 million.

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:

- 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, 90, and 91 Energy pricing options other than Cost of Service and the Energy Charge revenues from the Market Based Pricing Option from Schedules 485, 489, 490, 491, 492, and 495 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.
- Include reciprocating expense lubrication oil expenses. **(C)**

ADJUSTMENT AMOUNT

The amount accruing to the Power Cost Variance Account, whether positive or negative will be multiplied by a revenue sensitive factor of 1.0331 to account for franchise fees, uncollectables, and OPUC fees.

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 126 (Continued)

TIME AND MANNER OF FILING (Continued)

Included in this filing will be the following information:

1) A transmittal letter that summarizes the proposed changes.
2) Revised Power Cost Variance Rates.
3) Work papers supporting the calculation of the revised PCV rates.
4) The proposed Schedule 122 Qualifying Resource Cost Variance True-up **(C)**

If the Company finds that the PCV Rates may over or under collect revenues in a particular year, the Company may recommend a modification of the Adjustment Rates to the Commission. The Company may also recommend that the Commission consider Adjustment Rates based on a collection or refund period different than one year based on the balance in the PCV Account.

POWER COST VARIANCE RATES

The PCV Rates will be determined on an equal cents per kWh basis. The PCV Rates are:

Schedule	Adjustment Rate
7	0.000 ¢ per kWh
15	0.000 ¢ per kWh
32	0.000 ¢ per kWh
38	0.000 ¢ per kWh
47	0.000 ¢ per kWh
49	0.000 ¢ per kWh
75	
Secondary	0.000 ¢ per kWh(1)
Primary	0.000 ¢ per kWh(1)
Subtransmission	0.000 ¢ per kWh(1)
83	0.000 ¢ per kWh
85	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
89	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh

(1) Applicable only to the Baseline and Scheduled Maintenance Energy.
(2) Not applicable to Customers where service was received for the entire calendar year that the Annual Power Cost Variance accrued.

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, 90, 91 or 95 or Direct Access service on Schedules 515, 532, 538, 549, 575, 583, 585, 589, 590, 591, 592 and 595. This Schedule is not applicable to Customers served on Schedules 485, 489, 490, 491, 492 and 495.

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 2014, the Annual Short-Term Transition Adjustment Rate will be applied to their bills for service effective on and after January 1, 2015: **(C)** **(C)**

Schedule		Annual ¢ per kWh [1]	
32		2.018	**(R)**
38		1.883	
75	Secondary	1.563 [2]	
	Primary	1.533 [2]	
	Subtransmission	1.510 [2]	
83		1.987	
85	Secondary	1.819	
	Primary	1.790	**(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	1.563	**(R)**
	Primary	1.533	
	Subtransmission	1.510	
90		1.386	
91		1.435	
95		1.435	
515		1.435	
532		2.018	
538		1.883	
549		3.023	
575	Secondary	1.563 [(2)]	
	Primary	1.533 [(2)]	
	Subtransmission	1.510 [(2)]	
583		1.987	
585	Secondary	1.819	
	Primary	1.790	
589	Secondary	1.563	
	Primary	1.533	
	Subtransmission	1.510	
590		1.386	
591		1.435	
592		1.463	
595		1.435	**(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
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
90		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
590		0.000
591		0.000
592		0.000
595		0.000

(1) Applicable April 1, 2015 through December 31, 2015. **(C)**
(2) Not applicable to Customers served on Cost of Service.
(3) Applicable only to the Baseline and Scheduled Maintenance Energy.

SCHEDULE 143
SPENT FUEL ADJUSTMENT

PURPOSE

The purpose of this schedule is to implement in rates the amortization of the excess funds previously contained in the Trojan Nuclear Decommissioning Trust Fund and the pollution control tax credits associated with the Independent Spent Fuel Storage Installation at the Trojan nuclear plant.

APPLICABLE

To all bills for Electricity Service calculated under all schedules and contracts, except those Customers explicitly exempted.

PART A – TROJAN NUCLEAR DECOMMISSIONING TRUST FUND

Part A consists of the amortization of the excess funds previously contained in the Trojan Nuclear Decommissioning Trust Fund.

PART B – ISFSI ADJUSTMENT

Part B consists of the amortization of the payments from the Oregon Department of Energy related to state pollution control tax credits for the Independent Spent Fuel Storage Installation at Trojan.

ADJUSTMENT RATES

The Adjustment Rates, applicable for service on and after the effective date of this schedule, will be:

Schedule	Part A	Part B	Adjustment Rate	
7	(0.096)	(0.031)	(0.127)	¢ per kWh
15	(0.076)	(0.025)	(0.101)	¢ per kWh
32	(0.089)	(0.029)	(0.118)	¢ per kWh
38	(0.089)	(0.029)	(0.118)	¢ per kWh
47	(0.111)	(0.036)	(0.147)	¢ per kWh
49	(0.105)	(0.034)	(0.139)	¢ per kWh
75				
Secondary	(0.082)	(0.027)	(0.109)	¢ per kWh(1)
Primary	(0.080)	(0.026)	(0.106)	¢ per kWh(1)
Subtransmission	(0.079)	(0.026)	(0.105)	¢ per kWh(1)

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

SCHEDULE 143 (Continued)

ADJUSTMENT RATES (Continued)

Schedule	Part A	Part B	Adjustment Rate	
83	(0.089)	(0.029)	(0.118)	¢ per kWh
85				
Secondary	(0.086)	(0.028)	(0.114)	¢ per kWh
Primary	(0.084)	(0.027)	(0.111)	¢ per kWh
89				
Secondary	(0.082)	(0.027)	(0.109)	¢ per kWh
Primary	(0.080)	(0.026)	(0.106)	¢ per kWh
Subtransmission	(0.079)	(0.026)	(0.105)	¢ per kWh
90	(0.078)	(0.025)	(0.103)	¢ per kWh
91	(0.076)	(0.025)	(0.101)	¢ per kWh
92	(0.080)	(0.026)	(0.106)	¢ per kWh
95	(0.076)	(0.025)	(0.101)	¢ per kWh
485				
Secondary	(0.086)	(0.028)	(0.114)	¢ per kWh
Primary	(0.084)	(0.027)	(0.111)	¢ per kWh
489				
Secondary	(0.082)	(0.027)	(0.109)	¢ per kWh
Primary	(0.080)	(0.026)	(0.106)	¢ per kWh
Subtransmission	(0.079)	(0.026)	(0.105)	¢ per kWh
490	(0.078)	(0.025)	(0.103)	¢ per kWh
491	(0.076)	(0.025)	(0.101)	¢ per kWh
492	(0.080)	(0.026)	(0.106)	¢ per kWh
495	(0.076)	(0.025)	(0.101)	¢ per kWh

SCHEDULE 143 (Concluded)

ADJUSTMENT RATES (Continued)

Schedule	Part A	Part B	Adjustment Rate	
515	(0.076)	(0.025)	(0.101)	¢ per kWh
532	(0.089)	(0.029)	(0.118)	¢ per kWh
538	(0.089)	(0.029)	(0.118)	¢ per kWh
549	(0.105)	(0.034)	(0.139)	¢ per kWh
575				
Secondary	(0.082)	(0.027)	(0.109)	¢ per kWh(1)
Primary	(0.080)	(0.026)	(0.106)	¢ per kWh(1)
Subtransmission	(0.079)	(0.026)	(0.105)	¢ per kWh(1)
583	(0.089)	(0.029)	(0.118)	¢ per kWh
585				
Secondary	(0.086)	(0.028)	(0.114)	¢ per kWh
Primary	(0.084)	(0.027)	(0.111)	¢ per kWh
589				
Secondary	(0.082)	(0.027)	(0.109)	¢ per kWh
Primary	(0.080)	(0.026)	(0.106)	¢ per kWh
Subtransmission	(0.079)	(0.026)	(0.105)	¢ per kWh
590	(0.078)	(0.025)	(0.103)	¢ per kWh
591	(0.076)	(0.025)	(0.101)	¢ per kWh
592	(0.080)	(0.026)	(0.106)	¢ per kWh
595	(0.076)	(0.025)	(0.101)	¢ per kWh

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

BALANCING ACCOUNT

The Company will maintain balancing accounts to track the difference between the Trojan Nuclear Decommissioning Trust Fund refund and the ISFSI payments and the actual Schedule 143 revenues. This difference will accrue interest at the Commission-authorized rate for deferred accounts.

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	$470.00	$500.00	(R)
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 200 kW	$3.09	$3.04	(I)
Over 200 kW	$2.19	$2.14	|
per kW of monthly On-Peak Demand	$2.24	$2.20	(I)
System Usage Charge			
per kWh	(0.016) ¢	(0.017) ¢	(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 Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-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 $1.777 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 485 (Continued)

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.

LOSSES

The following adjustment factors will be used where losses are to be included in the Energy Charges:

Primary Delivery Voltage	1.0496	(I)
Secondary Delivery Voltage	1.0685	(R)

REACTIVE DEMAND CHARGE

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 applicable to this schedule are summarized in Schedule 100.

SPECIAL CONDITIONS

Customers selecting this schedule must enter into a written service agreement. In addition, the Customer acknowledges that:

1. Customer is giving up the right granted under state law to receive Electricity from the Company at a rate based on the cost of electric generating resources owned in whole or in part by the Company. Customers enrolled for service under the minimum Five-Year Option during Enrollment Periods A through L must give the Company not less than two years notice to terminate service under this schedule. Customers enrolled for service under the minimum Five-Year Option subsequent to Enrollment Period L must provide not less than three years notice to terminate service under this schedule. Such notices will be binding.

2. At the time service terminates under this schedule, the Customer will be considered a new Customer for purposes of determining available service options. A Customer served under the Company Supplied Energy option must meet the terms of the service agreement associated with that service prior to termination of service under this schedule.

3. The rate the Customer pays for Electricity may be higher or lower than the rates charged by the Company to similar customers not taking service under this schedule, including competitors to the Customer.

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	$5,440.00	$4,870.00	$5,600.00	(I)
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.97	$1.94	$1.94	(I)
Over 4,000 kW	$1.50	$1.47	$1.47	(I)
per kW of monthly On-Peak Demand	$2.24	$2.20	$0.83	(I)(R)
System Usage Charge				
per kWh	(0.036) ¢	(0.036) ¢	(0.037) ¢	(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 Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-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 $1.777 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 489 (Continued)

LOSSES

The following adjustment factors will be used where losses are to be included in the energy charges:

Subtransmission Delivery Voltage	1.0356	(I)
Primary Delivery Voltage	1.0496	(I)
Secondary Delivery Voltage	1.0685	(R)

REACTIVE DEMAND CHARGE

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 applicable to this schedule are summarized in Schedule 100.

SPECIAL CONDITIONS

Customers selecting this schedule must enter into a service agreement. In addition, the Customer acknowledges that:

1. Customer is giving up the right granted under state law to receive Electricity from the Company at a rate based on the cost of electric generating resources owned in whole or in part by the Company. Customers enrolled for service under the Minimum Five-Year Option during Enrollment Periods A through L must give the Company not less than two years notice to terminate service under this schedule. Customers enrolled for service under the minimum Five-Year Option subsequent to Enrollment Period L must provide not less than three years notice to terminate service under this schedule. Such notices will be binding.

2. At the time service terminates under this schedule, the Customer will be considered a new Customer for purposes of determining available service options. A Customer served under the Company Supplied Energy option must meet the terms of the service agreement associated with that service prior to termination of service under this schedule.

3. The rate the Customer pays for Electricity may be higher or lower than the rates charged by the Company to similar customers not taking service under this schedule, including competitors to the Customer.

SCHEDULE 490 (Continued)

MONTHLY RATE

The Monthly Rate will be the sum of the following charges per Point of Delivery (POD)*: **(C)**

Basic Charge	$25,000.00	**(I)**
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 4,000 kW	$1.08	**(R)**
Over 4,000 kW	$1.08	**(R)**
per kW of monthly On-Peak Demand	$2.20	**(I)**
System Usage Charge		
per kWh	(0.044) ¢	**(R)(C)**

* 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 490 (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 Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-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 $1.777 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 490 (Continued)

LOSSES

The following adjustment factors will be used where losses are to be included in the energy charges:

Subtransmission Delivery Voltage	1.0356	**(I)**
Primary Delivery Voltage	1.0496	**(I)**
Secondary Delivery Voltage	1.0685	**(R)**

REACTIVE DEMAND CHARGE

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 applicable to this schedule are summarized in Schedule 100.

SPECIAL CONDITIONS

Customers selecting this schedule must enter into a service agreement. In addition, the Customer acknowledges that:

(D)

1. Customer is giving up the right granted under state law to receive Electricity from the Company at a rate based on the cost of electric generating resources owned in whole or in part by the Company. Customers enrolled for service under the Minimum Five-Year Option must give the Company not less than three years notice to terminate service under this schedule. Such notice will be binding. **(T)**

2. At the time service terminates under this schedule, the Customer will be considered anew Customer for purposes of determining available service options. A Customer served under the Company Supplied Energy option must meet the terms of the service agreement associated with that service prior to termination of service under this schedule. **(T)**

SCHEDULE 490 (Concluded)

SPECIAL CONDITIONS (Continued)

3. The rate the Customer pays for Electricity may be higher or lower than the rates charged by the Company to similar customers not taking service under this schedule, including competitors to the Customer. **(T)**

4. Neither the Company, its employees and agents, the Commission nor any other agency of the State of Oregon has made any representation to the Customer regarding future Electricity prices that will result from the Customer's election of service under this schedule. **(T)**

5. The Customer is selecting this schedule based solely upon its own analysis of the benefits of this schedule. The Customer has available to it Energy experts that assisted in making this decision. **(T)**

6. The Customer warrants that the person signing the service agreement has full authority to bind the Customer to such agreement. **(T)**

7. Direct Access Service is available only on acceptance of a Direct Access Service Request (DASR) by the Company. A Customer is required to have interval metering and meter communications in place prior to initiation of service under this schedule. **(T)**

8. If the Customer is served at either primary or subtransmission voltage, the Customer will provide, install, and maintain on the Customer's premises all necessary transformers to which the Company's service is directly or indirectly connected. The Customer also will provide, install, and maintain the necessary switches, cutouts, protection equipment, and in addition, the necessary wiring on both sides of the transformers. All transformers, equipment, and wiring will be of types and characteristics approved by the Company, and the arrangement and operation of such equipment will be subject to the approval of the Company. **(T)**

9. Customers selecting service under this Schedule will be limited to a Company/ESS Split Bill. **(T)**

TERM

Minimum Five-Year Option
The term of service will not be less than five years. Service will be year-to-year thereafter. Customers must give the Company not less than three years notice to terminate service under this schedule. Such notice will be binding.

Fixed Three-Year Option
The term of service will be three years. Upon completion of this three year term, the Customer will select service under any other applicable rate schedule, subject to all notice requirements and provisions of the schedule.

SCHEDULE 491 (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 4.650 ¢ per kWh **(I)**

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.

SCHEDULE 491 (Continued)

MARKET BASED PRICING OPTION (Continued)

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.

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 Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-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 $1.777 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.

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.

LOSSES

The following adjustment factors will be used where losses are to be included in the energy charges: **(R)**

Secondary Delivery Voltage	1.0685

SCHEDULE 491 (Continued)

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rates [1]	Straight Time	Overtime
	$122.00 per hour	$163.00 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

		Nominal	Monthly	Monthly Rates			
Type of Light	Watts	Lumens	kWh	Option A	Option B	Option C	
Cobrahead Power Doors **							
	70	6,300	30	*	$ 2.76	$ 1.40	(I)(I)
	100	9,500	43	*	3.38	2.00	
	150	16,000	62	*	4.26	2.88	
	200	22,000	79	*	5.11	3.67	
	250	29,000	102	*	6.20	4.74	
	400	50,000	163	*	9.05	7.58	
Cobrahead, Non-Power Door	70	6.300	30	$ 6.45	3.01	1.40	(R) (I)
	100	9,500	43	6.99	3.60	2.00	
	150	16,000	62	7.90	4.49	2.88	
	200	22,000	79	9.43	5.35	3.67	
	250	29,000	102	10.47	6.42	4.74	
	400	50,000	163	13.72	9.31	7.58	
Flood	250	29,000	102	11.21	6.51	4.74	
	400	50,000	163	14.05	9.35	7.58	(I)
Early American Post-Top	100	9,500	43	7.75	3.69	2.00	(R)
Shoebox (Bronze color, flat	70	6,300	30	7.80	3.18	1.40	
Lens, or drop lens, multi-volt)	100	9,500	43	8.59	3.80	2.00	(R)(I)(I)
	150	16,000	62	9.73	4.72	2.88	

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

SCHEDULE 491 (Continued)

RATES FOR STANDARD POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Fiberglass, Black	20	$ 6.18	$0.14	(R)
Fiberglass, Bronze	30	9.74	0.22	(I)
Fiberglass, Gray	30	10.50	0.24	
Wood, Standard	30 to 35	7.03	0.16	
Wood, Standard	40 to 55	9.20	0.21	(R)(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	$11.88	$ 4.17	$ 2.00	(R)(R)(I)
HADCO Victorian, HPS	150	16,000	62	12.66	5.05	2.88	(I)
	200	22,000	79	14.17	5.96	3.67	
	250	29,000	102	15.29	7.03	4.74	
HADCO Capitol Acorn, HPS	100	9,500	43	15.60	4.63	2.00	
	150	16,000	62	16.42	5.55	2.88	
	200	22,000	79	17.19	6.33	3.67	
	250	29,000	102	18.28	7.41	4.74	
Special Architectural Types							
HADCO Independence, HPS	100	9,500	43	11.88	4.15	2.00	
	150	16,000	62	12.47	5.01	2.88	
HADCO Techtra, HPS	100	9,500	43	20.55	5.23	2.00	
	150	16,000	62	20.94	6.06	2.88	
	250	29,000	102	22.19	7.88	4.74	
HADCO Westbrooke, HPS	70	6,300	30	14.02	3.90	1.40	
	100	9,500	43	14.39	4.47	2.00	
	150	16,000	62	15.28	5.36	2.88	
	200	22,000	79	16.33	6.21	3.67	
	250	29,000	102	17.25	7.27	4.74	(R)(I)(I)

* Not offered.

SCHEDULE 491 (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	$ 8.44	$ 4.73	$ 2.79	(I)(I)(I)
Flood, Metal Halide	350	30,000	139	14.25	8.68	6.46	
Flood, HPS	750	105,000	285	22.65	15.96	13.25	(I)
Holophane Mongoose, HPS	150	16,000	62	13.11	5.10	2.88	(R)
	250	29,000	102	14.32	6.90	4.74	(R)(I)
Option C Only **							
Ornamental Acorn Twin	85	9,600	64	*	*	2.98	
Ornamental Acorn	55	2,800	21	*	*	0.98	
Ornamental Acorn Twin	55	5,600	42	*	*	1.95	
Composite, Twin	140	6,815	54	*	*	2.51	
	175	9,815	66	*	*	3.07	

(I)

RATES FOR CUSTOM POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Aluminum, Regular	16	$ 8.39	$0.19	(R)(I)
	25	13.93	0.31	
	30	15.05	0.34	
	35	18.00	0.40	(I)
Aluminum Davit	25	13.90	0.31	
	30	13.83	0.31	
	35	15.12	0.34	(I)
	40	20.52	0.46	
Aluminum Double Davit	30	20.42	0.46	
Aluminum, HADCO, Fluted Victorian Ornamental	14	12.29	0.28	

(R)(I)

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

SCHEDULE 491 (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	$24.18	$0.54	(R)(I)
Aluminum, HADCO, Fluted Ornamental	16	12.56	0.28	
Aluminum, HADCO, Non-Fluted Ornamental Westbrooke	16	25.69	0.58	(I)
Aluminum, HADCO, Fluted Westbrooke	18	24.24	0.54	
Aluminum, HADCO, Non-Fluted, Westbrooke	18	25.69	0.58	
Aluminum, Painted Ornamental	35	41.28	0.92	
Concrete, Decorative Ameron	20	24.12	0.54	
Concrete, Ameron Post-Top	25	24.12	0.54	(I)
Fiberglass, HADCO, Fluted Ornamental Black	14	14.86	0.33	
Fiberglass, Smooth	18	6.16	0.14	
Fiberglass, Regular,				
color may vary	22	5.51	0.12	
color may vary	35	9.04	0.20	
Fiberglass, Anchor Base, Gray	35	16.51	0.37	(I)
Fiberglass, Direct Bury with Shroud	18	9.96	0.22	(R)

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	Option C	
Cobrahead, Mercury Vapor	100	4,000	39	*	*	$ 1.81	(I)(I)(I)
	175	7,000	66	$ 8.01	$ 4.62	3.07	
	250	10,000	94	*	*	4.37	
	400	21,000	147	12.60	8.52	6.84	
	1,000	55,000	374	23.81	19.40	17.39	(I)(I)(I)

* Not offered.

SCHEDULE 491 (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	$ 7.89	$ 3.10	$ 1.40	(R)(I)(I)
Mercury Vapor	175	7,000	66	9.51	4.72	3.07	(I) (I)
Special box, Anodized Aluminum							
Similar to GardCo Hub							
HPS	Twin 70	6,300	60	*	*	2.79	
	70	6,300	30	*	*	1.40	
	100	9,500	43	*	4.06	2.00	(I)
	150	16,000	62	*	4.96	2.88	(I)
	250	29,000	102	*	*	4.74	
	400	50,000	163	*	*	7.58	
Metal Halide	250	20,500	99	*	5.88	4.60	(I)
	400	40,000	156	*	8.53	7.25	
Cobrahead, Metal Halide	175	12,000	71	9.18	5.07	3.30	(I)
Flood, Metal Halide	400	40,000	156	13.92	9.06	7.25	(I)
Cobrahead, Dual Wattage HPS							
70/100 Watt Ballast	100	9,500	43	*	3.61	2.00	
100/150 Watt Ballast	100	9,500	43	*	3.61	2.00	
100/150 Watt Ballast	150	16,000	62	*	4.51	2.88	
Special Architectural Types							
KIM SBC Shoebox, HPS	150	16,000	62	*	5.52	2.88	
KIM Archetype, HPS	250	29,000	102	*	7.61	4.74	
	400	50,000	163	*	9.85	7.58	(I)(I)

* Not offered

SCHEDULE 491 (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	$ 11.25	$ 3.54	$ 1.40	**(R)(I)(I)**
Special GardCo Bronze Alloy							
HPS	70	5,000	30	*	*	1.40	
Mercury Vapor	175	7,000	66	*	*	3.07	
Special Acrylic Sphere							
Mercury Vapor	400	21,000	147	*	*	6.84	
Early American Post-Top, HPS							
Black	70	6,300	30	7.04	2.98	1.40	
Rectangle Type	200	22,000	79	*	*	3.67	**(R)(I)**
Incandescent	92	1,000	31	*	*	1.44	
	182	2,500	62	*	*	2.88	
Town and Country Post-Top							
Mercury Vapor	175	7,000	66	8.72	4.66	3.07	**(I)(I)**
Flood, HPS	70	6,300	30	6.27	2.88	1.40	**(R)(R)**
	100	9,500	43	7.03	3.60	2.00	
	200	22,000	79	10.12	5.42	3.67	**(I)(I)**
Cobrahead, HPS							
Power Door	310	37,000	124	11.90	7.85	5.77	**(I)(I)**
Special Types Customer-Owned & Maintained							
Ornamental, HPS	100	9,500	43	*	*	2.00	
Twin ornamental, HPS	Twin 100	9,500	86	*	*	4.00	
Compact Fluorescent	28	N/A	12	*	*	0.56	

(I)

* Not offered.

SCHEDULE 491 (Continued)

RATES FOR OBSOLETE LIGHTING POLES

Type of Pole	Poles Length (feet)	Monthly Rates Option A	Option B	
Aluminum Post	30	$ 8.39	*	(R)
Bronze Alloy GardCo	12	*	$0.17	
Concrete, Ornamental	35 or less	13.93	0.31	(R)
Steel, Painted Regular **	25	13.93	0.31	
Steel, Painted Regular **	30	15.05	0.34	(R)(I)
Steel, Unpainted 6-foot Mast Arm **	30	*	0.31	
Steel, Unpainted 6-foot Davit Arm **	30	*	0.31	
Steel, Unpainted 8-foot Mast Arm **	35	*	0.34	
Steel, Unpainted 8-foot Davit Arm **	35	*	0.34	(I)
Wood, Laminated without Mast Arm	20	6.18	0.14	(R)
Wood, Laminated Street Light Only	20	6.18	*	
Wood, Curved Laminated	30	9.74	0.22	(I)
Wood, Painted Underground	35	7.03	0.16	(I)
Wood, Painted Street Light Only	35	7.03	*	(R)

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

SERVICE RATES FOR ALTERNATIVE LIGHTING

The purpose of this series of luminaires is to provide lighting utilizing the latest in technological advances in lighting equipment. The Company does not maintain an inventory of this equipment, and so delays with maintenance are likely. This equipment is more subject to obsolescence since it is experimental and yet to be determined reliable or cost effective. The Company will order and replace the equipment subject to availability.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Architectural Types Including Philips QL Induction Lamp Systems							
HADCO Victorian, QL	85	6,000	32	*	$ 2.26	$ 1.49	(I)(I)
	165	12,000	60	*	3.83	2.79	
	165	12,000	60	$24.65	4.02	2.79	(R)(I)(I)

SCHEDULE 492
TRAFFIC SIGNALS
COST OF SERVICE OPT-OUT

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 500 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. Service under this schedule is limited to the first 300 MWa that applies to Schedules 485, 489, 490, 491, 492, and 495

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	1.973 ¢ per kWh	**(I)**

* See Schedule 100 for applicable adjustments.

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 492 (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 Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-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 $1.777 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.

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.

LOSSES

The following adjustment factors will be used where losses are to be included in the energy charges:

Secondary Delivery Voltage	1.0685	**(R)**

ADJUSTMENTS

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

SCHEDULE 495 (Continued)

STREETLIGHT POLES SERVICE OPTIONS

Option A – Poles

See Schedule 91/491/591 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 4.650 ¢ per kWh **(I)**

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.

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 Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-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.

SCHEDULE 495 (Continued)

MARKET BASED PRICING OPTION (Continued)

Wheeling Charge

The Wheeling Charge will be $1.777 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.

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.

LOSSES

The following adjustment factors will be used where losses are to be included in the energy charges: **(R)**

Secondary Delivery Voltage	1.0685

SCHEDULE 495 (Continued)

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rates [(1)]	Straight Time	Overtime
	$122.00 per hour	$163.00 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	$3.96	(R)
LED	50	3,162	17	4.15	
LED	52	3,757	18	4.59	
LED	67	5,050	23	5.25	
LED	106	7,444	36	6.66	(R)

SCHEDULE 495 (Continued)

RATES FOR DECORATIVE LIGHTING

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

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rate Option A	
Acorn	60	5,488	21	$13.17	(R)
	70	4,332	24	15.19	
Westbrooke (Non-Flared)	49	5,094	17	17.76	
	69	6,680	24	18.86	
	109	8,176	37	19.73	
	136	12,728	46	23.80	
	206	18,159	70	24.92	
Westbrooke (Flared)	49	5,094	17	19.88	
	69	6,680	24	20.56	
	109	8,176	37	21.82	
	136	12,728	46	25.11	
	206	18,159	70	26.23	(R)

SPECIALTY SERVICES OFFERED

Upon Customer request and subject to the Company's operating constraints, 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.

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.

ADJUSTMENTS

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

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	$ 9.09 [2]	(I)
	400	21,000	147	13.25 [2]	|
	1,000	55,000	374	24.46 [2]	(I)
HPS	70	6,300	30	7.53 [2]	(R)
	100	9,500	43	8.07	(R)
	150	16,000	62	8.98	(I)
	200	22,000	79	10.08	|
	250	29,000	102	11.12	|
	310	37,000	124	12.55 [2]	|
	400	50,000	163	14.37	(I)
Flood , HPS	100	9,500	43	8.11 [2]	(R)
	200	22,000	79	10.77 [2]	(I)
	250	29,000	102	11.86	|
	400	50,000	163	14.70	(I)
Shoebox, HPS (bronze color, flat lens, or drop lens, multi-volt)	70	6,300	30	8.88	(R)
	100	9,500	43	9.67	|
	150	16,500	62	10.81	(R)

(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	$12.53	(R)
HADCO Victorian, HPS	150	16,500	62	13.31	
	200	22,000	79	14.82	
	250	29,000	102	15.94	
Early American Post-Top, HPS, Black	100	9,500	43	8.83	(R)
Special Types					
Cobrahead, Metal Halide	150	10,000	60	9.52	(I)
Cobrahead, Metal Halide	175	12,000	71	10.26	
Flood, Metal Halide	350	30,000	139	14.90	
Flood, Metal Halide	400	40,000	156	14.57	
Flood, HPS	750	105,000	285	23.30	(I)
HADCO Independence, HPS	100	9,500	43	12.53	(R)
	150	16,000	62	13.12	
HADCO Capitol Acorn, HPS	100	9,500	43	16.25	
	150	16,000	62	17.07	
	200	22,000	79	17.84	
	250	29,000	102	18.93	
HADCO Techtra, HPS	100	9,500	43	21.20	
	150	16,000	62	21.59	
	250	29,000	102	22.84	
HADCO Westbrooke, HPS	70	6,300	30	14.67	
	100	9,500	43	15.04	
	150	16,000	62	15.93	
	200	22,000	79	16.98	
	250	29,000	102	17.90	
KIM Archetype, HPS	250	29,000	102	20.73	(R)
	400	50,000	163	18.74	
Holophane Mongoose, HPS	150	16,000	62	13.76	(R)
	250	29,000	102	14.97	(R)

(1) See Schedule 100 for applicable adjustments.

SCHEDULE 515 (Continued)

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

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate[1] Per Luminaire	
Acorn					
LED	60	5,488	21	$13.62	(R)
	70	4,332	24	15.60	
Cobrahead					
LED	37	2,530	13	4.37	
	50	3,162	17	4.56	
	52	3,757	18	5.00	
	67	5,050	23	5.50	
	106	7,444	36	6.92	
Westbrooke LED (Non-Flare)	49	5,094	17	18.10	
	69	6,680	24	19.18	
	109	8,176	37	20.04	
	136	12,728	46	24.03	
	206	18,159	70	25.15	
Westbrooke LED (Flare)	49	5,094	17	20.17	
	69	6,680	24	20.84	
	109	8,176	37	22.09	
	136	12,728	46	25.31	
	206	18,159	70	26.43	(R)
CREE XSP LED	25	2529	9	3.23	(I)
	42	3819	14	3.56	(I)
	48	4373	16	4.12	
	56	5863	19	4.77	(R)
	91	8747	31	5.33	(I)

(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	$ 7.03	(R)
	40 to 55	9.20	
Wood, Painted Underground	35 or less	7.03 [2]	
Wood, Curved laminated	30 or less	8.71 [2]	
Aluminum, Regular	16	8.39	
	25	13.93	
	30	15.05	
	35	18.00	
Aluminum, Fluted Ornamental	14	12.29	
Aluminum Davit	25	12.88	
	30	13.83	
	35	15.12	
	40	20.52	
Aluminum Double Davit	30	20.42	
Aluminum, HADCO, Fluted Ornamental	16	12.56	
Aluminum, HADCO, Non-fluted	18	24.18	
Concrete, Ameron Post-Top	25	24.12	
Fiberglass Fluted Ornamental; Black	14	14.86	
Fiberglass, Regular			
Black,	20	6.18	
Gray or Bronze;	30	10.50	
Other Colors (as available)	35	9.04	
Fiberglass, Anchor Base Gray	35	16.51	
Fiberglass, Direct Bury with Shroud	18	9.96	(R)

(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	$15.00	(I)
Three Phase	$20.00	
Distribution Charge		
First 5,000 kWh	3.829 ¢ per kWh	
Over 5,000 kWh	0.873 ¢ per kWh	(I)

* 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, 2015. **(C)**

MONTHLY RATE

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

Basic Charge			
Single Phase Service	$25.00		
Three Phase Service	$25.00		
Distribution Charge	6.503	¢ 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**	$40.00	**(I)**
Winter Months**	No Charge	
Distribution Charge		
First 50 kWh per kW of Demand	5.964 ¢ per kWh	**(I)**
Over 50 kWh per kW of Demand	3.964 ¢ 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	$5,440.00	$4,870.00	$5,600.00	(I)
Distribution Charge				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.97	$1.94	$1.94	
Over 4,000 kW	$1.50	$1.47	$1.47	
per kW of monthly On-Peak Demand**	$2.24	$2.20	$0.83	(I)(R)
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	(0.036) ¢	(0.036) ¢	(0.037) ¢	(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**	$0.087	$0.086	$0.032	**(I)(R)**
Transaction Fee				**(D)**
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 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 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	
Three Phase Service	$40.00	
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 30 kW	$2.96	(I)
Over 30 kW	$2.86	
per kW of monthly On-Peak Demand	$2.24	(I)
System Usage Charge		
per kWh	0.518 ¢	(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 585
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE
(201 – 4,000 kW)

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 13 months, or with seven months or less of service has not had a Demand exceeding 4,000 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)*:

	Delivery Voltage		
	Secondary	Primary	
Basic Charge	$470.00	$500.00	(R)
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 200 kW	$3.09	$3.04	(I)
Over 200 kW	$2.19	$2.14	|
per kW of monthly On-Peak Demand	$2.24	$2.20	(I)
System Usage Charge			
per kWh	(0.016) ¢	(0.017) ¢	(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)

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.

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	$5,440.00	$4,870.00	$5,600.00	(I)
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.97	$1.94	$1.94	
Over 4,000 kW	$1.50	$1.47	$1.47	
per kW of monthly on-peak Demand	$2.24	$2.20	$0.83	(I)(R)
System Usage Charge				
per kWh	(0.036) ¢	(0.036) ¢	(0.037) ¢	(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 590
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE
(>4,000 kW and Aggregate to >100 MWa)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer who meet the following conditions: 1) Individual account 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 2) where combined usage of all accounts meeting condition 1 for the Large Nonresidential Customer aggregate to at least 100 MWa in a calendar year; and 3) the customer maintains a load factor of 80% or greater for each account; and 4) who has chosen to receive Electricity from an 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)*: **(C)**

Basic Charge	$25,000.00	**(I)**
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 4,000 kW	$1.08	**(R)**
Over 4,000 kW	$1.08	**(R)**
per kW of monthly on-peak Demand	$2.20	**(I)**
System Usage Charge		
per kWh	(0.044) ¢	**(R)(C)**

* 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 590 (Concluded)

SPECIAL CONDITIONS (D)

1. A Customer is required to have interval metering and meter communications in place prior to initiation of service under this schedule. (T)

2. If the Customer is served at either primary or subtransmission voltage, the Customer will provide, install, and maintain on the Customer's premises all necessary transformers to which the Company's service is directly or indirectly connected. The Customer also will provide, install, and maintain the necessary switches, cutouts, protection equipment, and in addition, the necessary wiring on both sides of the transformers. All transformers, equipment, and wiring will be of types and characteristics approved by the Company, and the arrangement and operation of such equipment will be subject to the approval of the Company. (T)

TERM

Service will be for not less than one year or as otherwise provided under this schedule.

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	4.650 ¢ 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
	$122.00 per hour	$163.00 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	*	$ 2.76	$ 1.40	(I)(I)
	100	9,500	43	*	3.38	2.00	
	150	16,000	62	*	4.26	2.88	
	200	22,000	79	*	5.11	3.67	
	250	29,000	102	*	6.20	4.74	
	400	50,000	163	*	9.05	7.58	
Cobrahead, Non-Power Door	70	6.300	30	$ 6.45	3.01	1.40	(R) (I)
	100	9,500	43	6.99	3.60	2.00	
	150	16,000	62	7.90	4.49	2.88	
	200	22,000	79	9.43	5.35	3.67	
	250	29,000	102	10.47	6.42	4.74	
	400	50,000	163	13.72	9.31	7.58	
Flood	250	29,000	102	11.21	6.51	4.74	
	400	50,000	163	14.05	9.35	7.58	(I)
Early American Post-Top	100	9,500	43	7.75	3.69	2.00	(R)
Shoebox (Bronze color, flat	70	6,300	30	7.80	3.18	1.40	
Lens, or drop lens, multi-volt)	100	9,500	43	8.59	3.80	2.00	(R)(I)(I)
	150	16,000	62	9.73	4.72	2.88	

* 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	$ 6.18	$0.14	(R)
Fiberglass, Bronze	30	9.74	0.22	(I)
Fiberglass, Gray	30	10.50	0.24	
Wood, Standard	30 to 35	7.03	0.16	
Wood, Standard	40 to 55	9.20	0.21	(R)(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	$11.88	$ 4.17	$ 2.00	(R)(I)(I)
HADCO Victorian, HPS	150	16,000	62	12.66	5.05	2.88	
	200	22,000	79	14.17	5.96	3.67	
	250	29,000	102	15.29	7.03	4.74	
HADCO Capitol Acorn, HPS	100	9,500	43	15.60	4.63	2.00	
	150	16,000	62	16.42	5.55	2.88	
	200	22,000	79	17.19	6.33	3.67	
	250	29,000	102	18.28	7.41	4.74	
Special Architectural Types							
HADCO Independence, HPS	100	9,500	43	11.88	4.15	2.00	
	150	16,000	62	12.47	5.01	2.88	
HADCO Techtra, HPS	100	9,500	43	20.55	5.23	2.00	
	150	16,000	62	20.94	6.06	2.88	
	250	29,000	102	22.19	7.88	4.74	
HADCO Westbrooke, HPS	70	6,300	30	14.02	3.90	1.40	
	100	9,500	43	14.39	4.47	2.00	
	150	16,000	62	15.28	5.36	2.88	
	200	22,000	79	16.33	6.21	3.67	
	250	29,000	102	17.25	7.27	4.74	(R)(I)(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	$ 8.44	$ 4.73	$ 2.79	(I)(I)(I)
Flood, Metal Halide	350	30,000	139	14.25	8.68	6.46	
Flood, HPS	750	105,000	285	22.65	15.96	13.25	
Holophane Mongoose, HPS	150	16,000	62	13.11	5.10	2.88	(I) (R)
	250	29,000	102	14.32	6.90	4.74	(R)(I)
Option C Only **							
Ornamental Acorn Twin	85	9,600	64	*	*	2.98	
Ornamental Acorn	55	2,800	21	*	*	0.98	
Ornamental Acorn Twin	55	5,600	42	*	*	1.95	
Composite, Twin	140	6,815	54	*	*	2.51	
	175	9,815	66	*	*	3.07	(I)

RATES FOR CUSTOM POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Aluminum, Regular	16	$ 8.39	$0.19	(R)(I)
	25	13.93	0.31	
	30	15.05	0.34	(I)
	35	18.00	0.40	
Aluminum Davit	25	13.90	0.31	
	30	13.83	0.31	(I)
	35	15.12	0.34	
	40	20.52	0.46	
Aluminum Double Davit	30	20.42	0.46	
Aluminum, HADCO, Fluted Victorian Ornamental	14	12.29	0.28	(R)(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	$24.18	$0.54	(R)(I)
Aluminum, HADCO, Fluted Ornamental	16	12.56	0.28	
Aluminum, HADCO, Non-Fluted Ornamental Westbrooke	16	25.69	0.58	(I)
Aluminum, HADCO, Fluted Westbrooke	18	24.24	0.54	
Aluminum, HADCO, Non-Fluted, Westbrooke	18	25.69	0.58	
Aluminum, Painted Ornamental	35	41.28	0.92	
Concrete, Decorative Ameron	20	24.12	0.54	
Concrete, Ameron Post-Top	25	24.12	0.54	(I)
Fiberglass, HADCO, Fluted Ornamental Black	14	14.86	0.33	
Fiberglass, Smooth	18	6.16	0.14	
Fiberglass, Regular,				
color may vary	22	5.51	0.12	
color may vary	35	9.04	0.20	
Fiberglass, Anchor Base, Gray	35	16.51	0.37	(I)
Fiberglass, Direct Bury with Shroud	18	9.96	0.22	(R)

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	*	*	$ 1.81	(I)
	175	7,000	66	$ 8.01	$ 4.62	3.07	(I)(I)
	250	10,000	94	*	*	4.37	
	400	21,000	147	12.60	8.52	6.84	(I)(I)
	1,000	55,000	374	23.81	19.40	17.39	(I)(I)(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	$ 7.89	$ 3.10	$ 1.40	(R)(I)(I)
Mercury Vapor	175	7,000	66	9.51	4.72	3.07	(I)(I)(I)
Special box, Anodized Aluminum							
Similar to GardCo Hub							
HPS	Twin 70	6,300	60	*	*	2.79	
	70	6,300	30	*	*	1.40	
	100	9,500	43	*	4.06	2.00	(I)
	150	16,000	62	*	4.96	2.88	(I)
	250	29,000	102	*	*	4.74	
	400	50,000	163	*	*	7.58	
Metal Halide	250	20,500	99	*	5.88	4.60	(I)
	400	40,000	156	*	8.53	7.25	
Cobrahead, Metal Halide	175	12,000	71	9.18	5.07	3.30	(I)
Flood, Metal Halide	400	40,000	156	13.92	9.06	7.25	(I)
Cobrahead, Dual Wattage HPS							
70/100 Watt Ballast	100	9,500	43	*	3.61	2.00	
100/150 Watt Ballast	100	9,500	43	*	3.61	2.00	
100/150 Watt Ballast	150	16,000	62	*	4.51	2.88	
Special Architectural Types Including Philips QL Induction Lamp Systems							
HADCO Victorian, QL	85	6,000	32	*	$ 2.26	$ 1.49	
	165	12,000	60	*	3.83	2.79	
	165	12,000	60	$24.65	4.02	2.79	(R)
Special Architectural Types							
KIM SBC Shoebox, HPS	150	16,000	62	*	5.52	2.88	
KIM Archetype, HPS	250	29,000	102	*	7.61	4.74	
	400	50,000	163	*	9.85	7.58	(I)(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	$ 11.25	$ 3.54	$ 1.40	(R)(I)(I)
Special GardCo Bronze Alloy							
HPS	70	5,000	30	*	*	1.40	
Mercury Vapor	175	7,000	66	*	*	3.07	
Special Acrylic Sphere							
Mercury Vapor	400	21,000	147	*	*	6.84	
Early American Post-Top, HPS							
Black	70	6,300	30	7.04	2.98	1.40	(R)(I)
Rectangle Type	200	22,000	79	*	*	3.67	
Incandescent	92	1,000	31	*	*	1.44	
	182	2,500	62	*	*	2.88	
Town and Country Post-Top							
Mercury Vapor	175	7,000	66	8.72	4.66	3.07	(I)(I)
Flood, HPS	70	6,300	30	6.27	2.88	1.40	(R)(R)
	100	9,500	43	7.03	3.60	2.00	(I)(I)
	200	22,000	79	10.12	5.42	3.67	
Cobrahead, HPS							
Power Door	310	37,000	124	11.90	7.85	5.77	(I)(I)
Special Types Customer-Owned & Maintained							
Ornamental, HPS	100	9,500	43	*	*	2.00	
Twin ornamental, HPS	Twin 100	9,500	86	*	*	4.00	
Compact Fluorescent	28	N/A	12	*	*	0.56	(I)

* Not offered.

SCHEDULE 591 (Continued)

RATES FOR OBSOLETE LIGHTING POLES

Type of Pole	Poles Length (feet)	Monthly Rates Option A	Option B	
Aluminum Post	30	$ 8.39	*	**(R)**
Bronze Alloy GardCo	12	*	$0.17	
Concrete, Ornamental	35 or less	13.93	0.31	**(R)**
Steel, Painted Regular **	25	13.93	0.31	
Steel, Painted Regular **	30	15.05	0.34	**(R)(I)**
Steel, Unpainted 6-foot Mast Arm **	30	*	0.31	
Steel, Unpainted 6-foot Davit Arm **	30	*	0.31	
Steel, Unpainted 8-foot Mast Arm **	35	*	0.34	
Steel, Unpainted 8-foot Davit Arm **	35	*	0.34	**(I)**
Wood, Laminated without Mast Arm	20	6.18	0.14	**(R)**
Wood, Laminated Street Light Only	20	6.18	*	
Wood, Curved Laminated	30	9.74	0.22	**(I)**
Wood, Painted Underground	35	7.03	0.16	**(I)**
Wood, Painted Street Light Only	35	7.03	*	**(R)**

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

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	1.973 ¢ per kWh	**(I)**

* 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 (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 4.650 ¢ per kWh **(I)**

Energy Charge Provided by Energy Service Supplier

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rates [1]	Straight Time	Overtime
	$122.00 per hour	$163.00 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	$3.96	(R)
LED	50	3,162	17	4.15	
LED	52	3,757	18	4.59	
LED	67	5,050	23	5.25	
LED	106	7,444	36	6.66	(R)

SCHEDULE 595 (Continued)

RATES FOR DECORATIVE LIGHTING

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

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rate Option A	
Acorn	60	5,488	21	$13.17	(R)
	70	4,332	24	15.19	
Westbrooke (Non-Flared)	49	5,094	17	17.76	
	69	6,680	24	18.86	
	109	8,176	37	19.73	
	136	12,728	46	23.80	
	206	18,159	70	24.92	
Westbrooke (Flared)	49	5,094	17	19.88	
	69	6,680	24	20.56	
	109	8,176	37	21.82	
	136	12,728	46	25.11	
	206	18,159	70	26.23	(R)

SPECIALTY SERVICES OFFERED

Upon Customer request and subject to the Company's operating constraints, 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.

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 600 (Concluded)

SPECIAL CONDITION

The ESS must purchase firm Transmission Service under the Company's OATT for not less than one-month duration and will be charged at the OATT monthly rate for firm transmission.

PGE SYSTEM LOSSES

The ESS will schedule sufficient Energy to provide for the following losses on the Company's system:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Losses:	4.74%	2.85%	1.45%	**(R)(I)**

SCHEDULE 750
INFORMATIONAL ONLY: FRANCHISE FEE RATE RECOVERY

PURPOSE

To inform customers regarding the level of franchise fee rate recovery contained in each schedule's system usage or distribution charges.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all Residential and Nonresidential Customers located within the Company's service territory.

FRANCHISE FEE RATE RECOVERY

The Rates, included in the applicable system usage and distribution charges are:

Schedule	Franchise Fee Rate		Included in:
7	0.293	¢ per kWh	Distribution Charge
15	0.584	¢ per kWh	Distribution Charge
32	0.269	¢ per kWh	Distribution Charge
38	0.326	¢ per kWh	Distribution Charge
47	0.691	¢ per kWh	Distribution Charge
49	0.570	¢ per kWh	Distribution Charge
75			
Secondary	0.161	¢ per kWh	System Usage Charge
Primary	0.158	¢ per kWh	System Usage Charge
Subtransmission	0.156	¢ per kWh	System Usage Charge
76R			
Secondary	0.000	¢ per kWh	System Usage Charge
Primary	0.000	¢ per kWh	System Usage Charge
Subtransmission	0.000	¢ per kWh	System Usage Charge

SCHEDULE 750 (Continued)

FRANCHISE FEE RATE RECOVERY (Continued)

The Rates, included in the applicable system usage and distribution charges are:

Schedule	Franchise Fee Rate	Included in:
83	0.215 ¢ per kWh	System Usage Charge
85		
Secondary	0.189 ¢ per kWh	System Usage Charge
Primary	0.185 ¢ per kWh	System Usage Charge
89		
Secondary	0.161 ¢ per kWh	System Usage Charge
Primary	0.158 ¢ per kWh	System Usage Charge
Subtransmission	0.156 ¢ per kWh	System Usage Charge
90	0.148 ¢ per kWh	System Usage Charge
91	0.442 ¢ per kWh	Distribution Charge
92	0.185 ¢ per kWh	Distribution Charge
95	0.442 ¢ per kWh	Distribution Charge
485		
Secondary	0.059 ¢ per kWh	System Usage Charge
Primary	0.058 ¢ per kWh	System Usage Charge
489		
Secondary	0.040 ¢ per kWh	System Usage Charge
Primary	0.040 ¢ per kWh	System Usage Charge
Subtransmission	0.039 ¢ per kWh	System Usage Charge
490	0.033 ¢ per kWh	System Usage Charge
491	0.311 ¢ per kWh	Distribution Charge
492	0.048 ¢ per kWh	Distribution Charge
495	0.311 ¢ per kWh	Distribution Charge

SCHEDULE 750 (Concluded)

FRANCHISE FEE RATE RECOVERY (Concluded)

The Rates, included in the applicable system usage and distribution charges are:

Schedule	Franchise Fee Rate		Included in:
515	0.453	¢ per kWh	Distribution Charge
532	0.115	¢ per kWh	Distribution Charge
538	0.172	¢ per kWh	Distribution Charge
549	0.387	¢ per kWh	Distribution Charge
575			
Secondary	0.040	¢ per kWh	System Usage Charge
Primary	0.040	¢ per kWh	System Usage Charge
Subtransmission	0.039	¢ per kWh	System Usage Charge
576R			
Secondary	0.000	¢ per kWh	System Usage Charge
Primary	0.000	¢ per kWh	System Usage Charge
Subtransmission	0.000	¢ per kWh	System Usage Charge
583	0.061	¢ per kWh	System Usage Charge
585			
Secondary	0.059	¢ per kWh	System Usage Charge
Primary	0.058	¢ per kWh	System Usage Charge
590	0.033	¢ per kWh	System Usage Charge
591	0.311	¢ per kWh	Distribution Charge
592	0.048	¢ per kWh	Distribution Charge
595	0.311	¢ per kWh	Distribution Charge

DO NOT BILL

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 283

General Rate Case Filing
For Prices Effective January 1, 2015

PORTLAND GENERAL ELECTRIC COMPANY

Executive Summary

February 13, 2014

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 283

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.

This case is largely driven by the addition of two new generating plants, Port Westward 2 ("PW2") and Tucannon River Wind Farm ("Tucannon"). The need for these two plants was identified in PGE's 2009 Integrated Resource Plan ("IRP") and the action plan implementation from that IRP. The plants themselves were chosen through a robust Request for Proposals process in accordance with the Commission's rules and guidelines. They were identified as the least cost/least risk resources to fill the need. PW2 is expected to begin service to customers in the first quarter of 2015, and Tucannon in the first half of 2015. In accordance with past Commission practice, PGE requests that the new plants be incorporated into customer prices when they begin service to customers. The annualized revenue requirements for these projects are $51.4 million for PW2 and $46.7 million for Tucannon.

PGE's request in this case is comprised a modest increase related to base business, two proposed significant customer credits, and the costs of the two new generating plants. In summary, the request is as follows:

	Revenue Change	Percent Change
Base Business	$12.5 million	0.7%
Base Business with Customer Credits	($16.5) million	(0.9%)
Overall: Base Business, Customer Credits, and Two Generating Plants	$81.5 million	4.6%

PGE's base business increase request in this case is small. We just completed a 2014 test-year rate case and management has successfully contained costs for this 2015 test-year. PGE's 2014 budget is within $1.6 million, or 0.19%, of the costs included in PGE's 2014 test-year prices. The 2014 budget was then escalated for inflation to create the 2015 budget, and known changes included. The result is a base business (without the effects of PW2 and Tucannon) increase request of $12.5 million, or 0.7% effective January 1, 2015.

PGE has also included in its request several proposals to mitigate the price increase request in this docket. Among these is new tariff Schedule 143, Spent Fuel Adjustment. PGE recently settled litigation against the US Department of Energy ("DOE") seeking damages for the DOE's failure to fulfill its contractual obligation to remove the spent nuclear fuel from the Trojan site. PGE received about $44 million as partial compensation for storage expenses for the spent fuel. The litigation proceeds were deposited into the Trojan Nuclear Decommissioning Trust ("NDT"). PGE anticipates receiving an additional $6 million from the DOE while this case is pending. As a result of these damage payments by the DOE, the Trojan NDT is over-funded, and PGE seeks direction to refund approximately $50 million to customers over a three year period beginning January 1, 2015 through Schedule 143. In that same tariff Schedule, PGE seeks authorization to also refund to customers about $5.5 million related to state pollution tax credits for the Independent Spent Fuel Storage Installation ("ISFSI") at Trojan.

PGE also anticipates receiving in 2014 about $13 million plus interest from the Bonneville Power Administration for Residential Exchange Credit payments for settlement of litigation related to the 2008 Interim Agreement True-up payments. PGE proposes to pass this additional credit, with interest, to the appropriate customers over a two-year period beginning January 1, 2015, through tariff Schedule 102.

Including these Schedule 102 and 143 credits, PGE's requested price change (without the effects of PW2 and Tucannon) beginning January 1, 2015, is an overall decrease in revenues of $16.5 million, or 0.9% relative to current approved prices.

The overall request, including the costs of both new generating plants after they begin service, and the Schedule 102 and 143 credits, is an increase in revenues of $81.5 million, or 4.6% relative to currently approved prices. The fortunate timing of these credits to customers reduces the rate increase request in this docket by about 1.7% overall. The size of the requested increase also reflects a successful, diligent effort by PGE to keep costs down particularly at a time when two new generating plants, which cost about $800 million to construct, are brought into rates.

II. SUMMARY OF THIS CASE

As described below, fourteen pieces of testimony discuss the basis for our request in this case. 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 2015 costs incorporated into this case.

This case is based on a normalized future test period of calendar year 2015, except that for rate base we use the balance as of December 31, 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, 2015, with additional price changes implemented when PW2 and Tucannon begin service to customers. The dollar amounts of the changes were discussed above.

PGE requests an authorized return on equity (ROE) of 10.0%. The projected test year results show that inclusive of the new generating plants and without a price increase, PGE will earn an ROE of approximately 6.7%. 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, this case is predominantly about the addition of two new generating resources, needed to meet our customers' needs for safe, reliable service. Prices need to be set to allow PGE 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.

PGE's request with respect to the rate changes when the two new plants come on-line is consistent with past Commission practice. As has been done in previous dockets, when each of the plants is on-line, PGE will provide an attestation of a PGE officer verifying that the plant is in operation and available for service to customers. PGE requests that after the filing of such an attestation, rates including the costs of each plant become effective.

Environmental Expenses. In this case PGE also requests an accounting order for environmental expenses. Environmental clean-up expenses can occur in large lumps that may not mesh with normal test-year ratemaking. PGE requests an accounting order allowing it to spread certain environmental remediation costs and income over twenty years from the time they are incurred. This is not a request for a balancing account or any other true-up. It is only a request for an accounting order as described in the testimony. If this proposal is implemented, it will decrease 2015 test year expenses by about $3 million.

Renewable Portfolio Standard Mechanism. This case also includes proposed changes to PGE's Schedule 122 Renewable Resource Automatic Adjustment Clause tariff (the "RAC") to more accurately reflect the costs and benefits of renewable resources necessary for compliance with the Oregon Renewable Portfolio Standard. ORS 469A.120 provides that "…all prudently incurred costs associated with the compliance with a renewable portfolio standard are recoverable in the rates of an electric company…" As discussed in the testimony, PGE's proposed changes provide better implementation of this directive than current ratemaking. The proposal is set out and discussed in PGE Exhibit 500 submitted herewith.

Net Variable Power Costs. Each year under Schedule 125, PGE's prices 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 2014 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 without PW2 and Tucannon on each customer class. The impact on residential customers of the requested base business price change, prior to the inclusion of the new plants, is an increase of 1.7%. Including the impacts of Schedules 102 and 143, an average residential customer using 840 kWh per month will see a decrease of approximately 0.2% prior to inclusion of the new plants. Attached as Exhibit 2 is the OAR 860-022-0019 information reflecting the costs of PW2 and Tucannon, and the requested Schedule 102 and 143 credits to customers. With all of these elements, the requested price change for residential customers is 5.0%, and the increase for an average residential customer using 840 kWh per month is $4.92.

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 fourteen pieces of testimony sponsored by the following witnesses:

EXHIBIT NO.	TITLE	WITNESSES
100	Policy	Jim Piro and Jim Lobdell
200	Load Forecast	Ham Nguyen and Sarah Dammen
300	Revenue Requirements	Alex Tooman and Robert Macfarlane
400	Port Westward 2 and Tucannon River Wind Farm	Maria Pope and Jim Lobdell
500	Net Variable Power Costs	Mike Niman, Terri Peschka and Patrick Hager
600	Compensation	Arleen Barnett and Jardon Jaramillo
700	Corporate Support/A&G and Information Technology	Jim Lobdell, Cam Henderson and Alex Tooman
800	Production O&M	Steve Quennoz and David Weitzel
900	Transmission and Distribution	Bill Nicholson and Bruce Carpenter
1000	Customer Service	Kristin Stathis and Carol Dillin
1100	Cost of Capital	Patrick Hager, William Valach and Brett Greene
1200	Return on Equity	Thomas Zepp
1300	Marginal Cost of Service	Bruce Werner and Bonnie Gariety
1400	Pricing	Marc Cody

IV. SUMMARY OF TESTIMONY

Exhibit 100. Jim Piro, CEO and Jim Lobdell, CFO, present the opening testimony. They explain the business context for this filing including the addition of the two new generating plants, and identify other key proposals. They also discuss a potential transaction regarding a share of the Boardman plant. They continue describing the efficiency efforts PGE has successfully implemented, and credits proposed to mitigate the price increase requested in this docket. As the CEO and CFO, Messrs. Piro and Lobdell explain the policy drivers behind PGE's key proposals in this case, and why they are in the interests of customers. Messrs. Piro and Lobdell also introduce the other testimony in this docket.

Exhibit 200. Ham Nguyen, Senior Economist, and Sarah Dammen, Economist, present PGE's load forecast for 2015. They forecast that total retail loads will increase only slightly from 2014. As has been done in previous cases, PGE will update the load forecast during this case as updated economic and customer data become available.

Exhibit 300. Project Managers Alex Tooman and Robert Macfarlane summarize the overall 2015 test year revenue requirement and compare the request with 2014 costs recently addressed and included in rates in dockets UE 262 and 266. These witnesses also discuss PGE's request for new depreciation rates currently pending before the Commission in docket UM 1679, and use these requested rates in calculating revenue requirement in this docket. Messrs. Tooman and Macfarlane also discuss the request to withdraw excess funds from the Trojan decommissioning trust and refund them to customers, and the refund of certain ISFSI tax credit benefits. They also address the costs associated with the two new generating plants, PW2 and Tucannon, and how PGE proposes to include them in customer prices when they begin providing service to customers.

Exhibit 400. Maria Pope, Senior Vice President of Power Supply and Operations and Resource Strategy and Jim Lobdell describe the two new generating resources, PW2 and Tucannon. These witnesses briefly review the extensive planning and oversight that led to the selection of these two projects. The testimony addresses the costs of these resources, and the efforts to date to bring the projects into service for customers on time and on budget.

Exhibit 500. PGE Managers Mike Niman, Terri Peschka and Patrick Hager present PGE's Net Variable Power Costs. The initial NVPC forecast for 2015, exclusive of PW2 and Tucannon is \$593 million. This is a decrease of about \$1.41 per MWh, from the 2014 NVPC determined in PGE's recent Annual Update Tariff proceeding, Docket UE 266. The additional effect of PW2 and Tucannon further reduces NVPC by an estimated \$0.70 per MWh, but the actual reduction is dependent upon the on-line date of each plant. This testimony also addresses PGE's proposal to address renewable resources under PGE's RAC tariff to more accurately reflect the benefits and costs of these resources in customer prices.

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 2014 open access window.

Exhibit 600. Arleen Barnett, Vice President of Administration, and Jardon Jaramillo, Director of Compensation and Benefits, testify on compensation and human resource issues. They describe compensation costs for 2015, gains through efficiencies, changes to PGE compensation policies and plans, and proposed pension cost recovery and pension investment strategy.

Exhibit 700. Jim Lobdell, Cam Henderson, Vice President of Information Technology, and Alex Tooman explain the costs and drivers associated with PGE's corporate support

operations such as insurance, environmental services, business continuity and emergency management, and Information Technology.

Exhibit 800. PGE's long-term power supply resources and associated costs are presented by Steve Quennoz, Vice President of Power Supply, and David Weitzel, Senior Analyst, Financial Analysis Group. They also discuss PGE's potential participation in an Energy Imbalance Market, and the associated costs and benefits. These witnesses also address a potential transaction involving a share of the Boardman generating plant, recent plant performance and ongoing efforts to improve plant reliability and safety. These witnesses also provide support for the proposed major maintenance accrual for PW2.

Exhibit 900. Bill Nicholson, Senior Vice President of Customer Service, Transmission and Distribution, and Bruce Carpenter, Vice President of Distribution, testify regarding PGE's transmission and distribution ("T&D") system. They explain the test-year costs necessary to provide service and efficiency measures.

Exhibit 1000. Kristin Stathis, Vice President of Customer Service Operations, and Carol Dillin, Vice President of Customer Strategies and Business Development, address PGE's Customer Services functions and costs for 2015. 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 an update on the Customer Engagement Transformation project discussed in the last rate case. They also discuss implementation of the fee-free bank card program, and address improvement initiatives in the customer service area.

Exhibit 1100. Patrick Hager, Manager of Regulatory Affairs, William Valach, Director of Investor Relations, and Brett Greene, Assistant Treasurer and Director of Treasury and Tax, present PGE's testimony on cost of capital and capital structure for 2015. On behalf of PGE,

these witnesses request a 7.78% cost of capital for PGE. This includes an ROE of 10.0% and long-term debt cost of 5.557%. The witnesses address the impact of the Commission's decision regarding ROE 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 immediately previous rate cases, 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 ROE to be used in this docket.

Exhibit 1200. Economist 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 9.9% to 10.6%, with a recommendation that PGE's authorized ROE be no less than 10.3%.

Exhibit 1300. Bruce Werner and Bonnie Gariety, Pricing and Tariff Analysts, present PGE's marginal cost studies for distribution and customer service. Those studies are then used in determining rate spread, rate design, and proposed prices in this docket, as explained in Exhibit 1400.

Exhibit 1400. Marc Cody, Senior Pricing Analyst, testifies on pricing. Mr. Cody presents PGE's marginal cost study for generation. He then presents prices based on the marginal cost studies. Mr. Cody discusses PGE's proposed change to the residential basic charge. This testimony also presents proposed changes to various supplemental tariff schedules,

and supports the new Schedule 143 Spent Fuel 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. Authorizing and directing the withdrawal of excess funds from the Trojan decommissioning trust, and refunding of the excess funds to customers through the proposed Schedule 143;

ii. Issuance of an accounting order regarding environmental costs, spreading the costs, net of reimbursements, over twenty years;

iii. Adopting the changes to Schedule 122 implementing PGE's proposed renewable resource adjustment clause; and

iv. Implementing a major maintenance accrual for the Port Westward 2 plant.

Dated: this 13th day of February, 2014.

Respectfully submitted,

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Exhibit 1

Case Summary

Before PW2, Tucannon, and Supplemental Schedules

($000)

Total Revenue Requirement	$1,742,500
Change in Revenues Requested	
Total Change in Revenues Requested	$12,496
Total Change net of RPA	$5,905
Percent Change in Base Revenues Requested	0.9%
Percent Change net of RPA	0.4%
Test Period	2015
Requested Rate of Return on Capital (Rate Base)	7.78%
Requested Rate of Return on Common Equity	10.0%
Proposed Rate Base	$3,058,727
Results of Operation	
A. Before Price Change	
Utility Operating Income	$230,666
Average Rate Base	$3,054,217
Rate of Return on Capital	7.54%
Rate of Return on Common Equity	9.53%
B. After Price Change	
Utility Operating Income	$237,923
Average Rate Base	$3,058,727
Rate of Return on Capital	7.78%
Rate of Return on Common Equity	10.0%
Base Rate Effect of Proposed Price Change	
A. Residential Customers	1.7%
B. Small Non-residential Customers	0.8%
C. Large Non-residential Customers	-0.2%
D. Lighting & Signal Customers	0.0%
Note: Percent Changes are on a cycle basis for Cost of Service Customers	

Exhibit 2

Case Summary

Including PW2, Tucannon, and Supplemental Schedules

($000)

Total Requested Revenues (with supplementals)	$1,841,174
Change in Revenues Requested	$81,492
Percent Change in Revenues Requested	4.9%
Test Period	2015
Requested Rate of Return on Capital (Rate Base)	7.78%
Requested Rate of Return on Common Equity	10.0%
Proposed Rate Base	$3,859,789
Results of Operation	
A. Before Price Change	
Utility Operating Income	$236,040
Average Rate Base	$3,054,217
Rate of Return on Capital	6.12%
Rate of Return on Common Equity	6.68%
B. After Price Change	
Utility Operating Income	$300,234
Average Rate Base	$3,859,789
Rate of Return on Capital	7.78%
Rate of Return on Common Equity	10.0%
Base Rate Effect of Proposed Price Change	
A. Residential Customers	5.0%
B. Small Non-residential Customers	4.6%
C. Large Non-residential Customers	5.0%
D. Lighting & Signal Customers	1.9%
E. Cost of Service & Direct Access	4.6%
Note: Revenues and Percent Changes are on a cycle basis for Cost of Service Customers unless otherwise noted	

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused **ADVICE NO. 14-03 PORTLAND GENERAL ELECTRIC GENERAL RATE REVISION UE 283,** by electronic mail to those parties whose email addresses appear on the attached service list for OPUC Docket No. UE 262.

DATED at Portland, Oregon, this 13th day of February 2014.

Jay Tinker

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BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 283

General Rate Case Filing
For Prices Effective January 1, 2015

PORTLAND GENERAL ELECTRIC COMPANY

ACRONYMS

February 13, 2014

UE 283 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
AFUDC – Allowance for Funds Used during Construction
AGC – Automatic Generation Control
AMI – Advance Metering Infrastructure
AOP – Annual Operating Plan
ASC – Accounting Standards Codification
AUT – Annual Update Tariff
B – Base
BA – Balancing Authority
BAA – Balancing Authority Area
BAL – Bank of America Leasing LLC
BCEM – Business Continuity and Emergency Management
Bcf – Billion Cubic Feet
BETC – Business Energy Tax Credits
BPA – Bonneville Power Administration
BVPS – Book Value per Share
CAISO – California Independent System Operator
CCCT – Combined Cycle Combustion Turbine
CE – Cost Element
CEI – Critical Energy Infrastructure
CEO – Chief Executive Officer
CET – Customer Engagement Transformation
CFA – Chartered Financial Analyst
CFO – Chief Financial Officer
CIAC – Contributions in Aid of Construction
CIP – Critical Infrastructure Protection
CIS – Customer Information System
CMC – Customer Marginal Costs
CME – Chicago Mercantile Exchange
COS – Cost of Service
CPP – Critical Peak Pricing
CRH Line – Cold Reheat Line
CRPC – Columbia River Power Constructors
CRRA – Certified Rate of Return Analyst
CS&BD – Customer Strategies and Business Development
CSI – Centralization, Standardization and Integration
CSO – Customer Service Operations
CTG – Combustion Turbine Generator
CWIP – Construction Work in Progress
D&O – Directors and Officers

DCF – Discounted Cash Flow
DEQ – Department of Environmental Quality
DOE – Department of Energy
DP – Dynamic Programming
DPS – Dividends per Share
DRA – Division of Ratepayer Advocates
DSG – Dispatchable Standby Generation
DSI – Dry Sorbent Injection
E – Post Price-Effect
EBITDA – Earnings Before Interest, Taxes, Depreciation and Amortization
EDD – Employment Development Department
EDI – Electronic Data Interchange
EE – Energy Efficiency
EFSC – Energy Facility Siting Council
EIA – Energy Information Administration
EIM – Energy Imbalance Market
EOH – Equivalent Operating Hours
EPA – Environmental Protection Agency
EPS – Earnings per Share
ERISA – Employee Retirement Income Security Act
ERPs – Equity Risk Premiums
ES – Environmental Service
ESS – Energy Service Supplier
ETO – Energy Trust of Oregon
EV – Electric Vehicle
F&A – Finance and Accounting
FAS – Financial Accounting Standards
Fed – Federal Reserve
FERC – Federal Energy Regulatory Commission
FICA – Federal Insurance Contributions Act
FITNES – Facility Inspections and Treatment to the National Electric Safety Code
FMBs – First Mortgage Bonds
FS – Feasibility Study
FSEC – Financial Systems Effectiveness Committee
FSRP – Financial Systems Replacement Project
FTE – Full Time Equivalent
GAAP – Generally Accepted Accounting Principles
GAWE – Guaranteed Availability and Warranty Extension
GDP – Gross Domestic Product
GECC – General Electric Credit Corporation
GF – General Foreman
GH – Garrad Hassan America
GIS – Geospatial Information System
GRC – General Rate Case
GWD – Graphic Work Design
HP/IP – High Pressure and Intermediate Pressure turbine

HPS – High pressure sodium
HR – Human Resources
HRA – Health Reimbursement Account
HRSG – Heat Recovery Steam Generator
I&C – Instrument and Control
IBEW – International Brotherhood of Electrical Workers
IC – Industrial Composite
ICE – IntercontinentalExchange
IE – Independent Evaluator
IPC – Idaho Power Company
IRP – Integrated Resource Plan
ISFSI – Independent Spent Fuel Storage Installation
ISO – Independent System Operator
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
LGIA – Large Generator Interconnection Agreement
LRRA – Lost Revenue Recovery Adjustment
LSR – Lower Snake River
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
MH – Metal Halide
Mid-C – Mid-Columbia
MONET – Multi-area Optimization Network Energy Transaction model
MPPS – Market Price per Share
MSI – Market Strategies International
MT – Magnetic Particle Testing
MV – Mercury Vapor
MWa – Megawatt average
MWh – Megawatt hours
NAICS – North America Industry Classification System
NCP – Non-coincident peak
NDE – Non-Destructive Examination
NDT – Nuclear Decommissioning Trust
NEPA – National Environmental Policy Act
NERC – North American Electric Reliability Corporation

NIST – National Institute of Standards and Technology
NRC – Nuclear Regulatory Commission
NRSS – Non-running Station Service
NVPC – Net Variable Power Cost
NWN – Northwest Natural
NWPP MC – Northwest Power Pool Members Market Assessment and Coordination Committee
O&M – Operations and Maintenance
OATT – Open Access Transmission Tariff
OBI – Oracle Business Intelligence
ODEQ – Oregon Department of Environmental Quality
OEA – Office of Economic Analysts
OMS – Outage Management System
OMSI – Oregon Museum of Science and Industry
OOA – Ownership and Operation Agreement
OPIS – Oil Price Information Service
OSHA – Occupational Safety and Health Administration
OTC – Over-the-Counter
P – Price-Effect
PAC – PacificCorp
PAS – Publicly Available Specification
PBO – Pension Benefit Obligation
PCAM – Power Cost Adjustment Mechanism
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
PRB – Pelton and Round Butte plants
PRC – Power Resources Cooperative
PRPs – Potentially Responsible Parties
PSC – Portland Service Center
PSE – Puget Sound Energy
PSES – Power Supply Engineering Services
PT – Liquid penetrant method
PTCs – Production Tax Credits
PTP – Point-to-Point
PTSAs – Precedent Transmission Service Agreements
PUD – Public Utility District
PwC – Price Waterhouse Coopers
PW1 – Port Westward 1
PW2 – Port Westward 2
R&D – Research and Development
R&ME – Reliability and Maintenance Excellence
RAP – Remedial Action Report

RC – Responsibility Center
RCA – Root Cause Analysis
RCM – Reliability Centered Maintenance
RE – Regional Entity
RES – Renewable Energy Standard
RFP – Request for Proposals
RI – Remedial Investigation
RLCOE – Real Levelized Cost of Energy
ROE – Return on Equity
ROM – Resource Optimization Model
RROE – Required Return on Equity
RP – Risk Premium
RPS – Renewable Portfolio Standard
RRMP – Recreation Resources Management Plan
RSP – Retirement Savings Plan
RTO – Regional Transmission Organization
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
SCD – Scheduling Control and Dispatch
SCED – Security Constrained Economic Dispatch
SEC – Securities Exchange Commission
SEDC – Safe and Efficient Design Construction
SEI – Siemens Energy
SEM – Scanning Electron Microscope
SERP – Supplemental Executive Retirement Plan
SFAS – Statement of Financial Accounting Standards
SHARP – Safety and Health Achievement Recognition Program
SIP – Strategic Investment Program
SITF – Supervisor in the Field
SMA – Service and Maintenance Agreement
SME – Soy Methyl Ester
SNA – Sales Normalization Adjustment
SQM – Service Quality Measure
T&D – Transmission and Distribution
TCC – Tualatin Contact Center
TID – Turlock Irrigation District
TIV – Total Insured Value
TOU – Time-of-Use
TQS – TQS Research, Inc.
TSRs – Transmission Service Requests
UAM – Utility Asset Management
UG – Underground

USWC – US West Communications
UT – Utrasonic testing
VERBS – Variable Energy Resource Balancing Service
VIE – Variable Interest Entities
VoIP – Voice over Internet Protocol
VPP – Voluntary Protection Program
W&S – Wages and Salaries
WECC – Western Energy Coordinating Council
WIES – Western Interconnected Electric Systems
WMS – Work Management System
WNA – Wärtsilä North America
WSATA – Western States Association of Tax Administrators
WSPWE – Warm Spring Power and Water Enterprises
WTG – Wind Turbine Generators

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 283

General Rate Case Filing
For Prices Effective January 1, 2015

PORTLAND GENERAL ELECTRIC COMPANY

DIRECT TESTIMONY AND EXHIBITS

February 13, 2014

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 283

Policy

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony of

Jim Piro
Jim Lobdell

February 13, 2014

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I. Introduction

Q. Please state your name and position with Portland General Electric.

A. My name is James J. Piro. I am the President and Chief Executive Officer for PGE.

My name is Jim Lobdell. I am the Senior Vice President, Finance, Chief Financial Officer, and Treasurer at PGE. Our qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to:

- Describe the context for this filing and the addition of two generating plants coming on line in the first part of 2015 with a resulting price increase of 4.6%;
- Describe how these plants meet our Integrated Resource Plan (IRP) identified resource needs for flexible capacity and renewable resources required by Oregon's Renewable Portfolio Standard (RPS);
- Discuss PGE's continuous improvement efforts and summarize the efficiency savings we have achieved through 2015;
- Discuss our mitigation of the price increase;
- Highlight the potential for new resource acquisition; and
- Identify our other key proposals.

My testimony is organized according to these objectives.

II. Context

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

A. The business context is our responsibility to provide safe, reliable electricity at a reasonable price for our customers. This context is influenced by the economy, customer choices and preferences, and compliance with regulations – including our mandate to plan and implement long term strategies to meet our customers' energy needs with both demand and supply-side resources that provide the best balance of cost and risk over time.

Q. How is PGE's business context influenced by the economy?

A. The economy influences our business context because economic growth drives load growth, and load growth enables us to absorb normal inflationary cost increases. While industrial loads are a cautious bright spot in the forecast, we expect flat to decreasing loads for commercial and residential customers when compared with 2013 actual deliveries. The economy is seeing a slow recovery and our customers are still feeling the effects of the recent recession. Recognizing this, we continue to focus on a culture of efficiency and keeping our operations and maintenance (O&M) costs contained at a relatively flat level overall when compared with the costs reflected in our last general rate case order.

Q. With regard to containing costs to a relatively flat level, what do you mean by flat?

A. Flat means flat compared to the approved levels and prices in our last general rate case. To be more specific, we concluded our general rate case with a Commission order in December 2013 based on a 2014 test year. During that rate case process (UE 262), we justified the increases to the 2014 test year by making comparisons to the 2011 actual expenses. With our current filing, rather than base our 2015 test year budget assumptions on 2012 actual expenses, we used the final approved 2014 test year costs and resulting prices. PGE Exhibit 300 provides more detail.

Q. How is PGE's business context influenced by customer choices and preferences?

A. We are in business to serve our customers, and our customers have alternatives: nonresidential customers may choose an alternate energy supplier and residential customers have fuel choices and distributed technologies.

In addition, support for energy efficiency as the resource of choice – among public policy makers, regulators, customer advocates, and within PGE itself – reduces load growth that would otherwise be expected to accompany population and economic expansion. This prioritization of energy efficiency mirrors our customers' preferences as well, and is reflected by a 16% reduction in average monthly residential energy use since 2000. We support, and will continue to support, energy efficiency because it is the right thing to do and benefits our customers and our service area in many ways. To give more perspective on our support for energy efficiency, in 2013, we collected about $87 million for the Energy Trust of Oregon (ETO) and other agencies to fund programs for our customers to be more energy efficient. In the PGE 2013 Draft IRP released in November 2013, the ETO's projection for cost-effective energy efficiency acquired is 33.7 MWa for 2013, 34.0 MWa for 2014 and 31.6 MWa for 2015. The projected 31.6 MWa energy efficiency is approximately 1.5% of PGE's cost of service test year load forecast.

Q. Are there other consequences to PGE's commitment to pursue cost-effective energy efficiency?

A. Yes. In the long-run, our commitment to energy efficiency helps PGE displace the need for long-term, supply-side resources and we are steadfast in our commitment to cost-effective energy efficiency as a 'first choice' resource. However, in the short-term, energy efficiency leads to reduced contributions to our existing fixed costs, which raises customer prices. For example, absent the 2014 target of 34.0 MWa of energy efficiency, the additional revenues to PGE in 2015 would have allowed us to forgo the requested base revenue requirement increase in this case before consideration of Port Westward 2 (PW2) and the Tucannon River Wind Farm (Tucannon).

Q. What else do customers expect of us?

A. In addition, to support energy efficiency, customers expect us to deliver electricity safely and effectively to them, while also fulfilling broader mandates for a changing resource mix, with a smaller environmental footprint and compliance with all applicable standards and regulations. PW2, consisting of twelve natural gas reciprocating engines and located adjacent to the Port Westward 1 plant, provides the flexible capacity PGE needs. Tucannon is coming into service to provide wind power to customers and help us meet the RPS.

Q. How is PGE's business context influenced by compliance with regulations?

A. Electricity generation and delivery is essential to our economy, society and all our lives. Just about every activity PGE is engaged in is regulated by one or more government entities. This is just a fact of being in the utility business. We recognize our responsibility as an essential service provider. Safe, ethical and compliant business practices are among our core principles that underpin everything we do.[1] Extensive and complex regulatory requirements also raise the costs of doing business. Regulation is increasing, growing in complexity, and ever changing. We must hire experienced people to keep abreast of regulations and compliance while planning for the continued reliability of our operations and systems.

[1] The other core principles are continuous improvement, diversity and inclusion, community investment and environmental stewardship.

Q. What are your goals for PGE?

A. First and foremost: deliver safe, reliable and reasonably priced electricity to customers with excellent customer service while complying with all applicable laws and regulations. We have strong core values that reflect our commitment to our customers, employees, community and shareholders. If we are successful, we will also 1) be a preferred employer, attracting and retaining the best people; 2) maintain a reputation as a caring and invested community partner, and 3) attract investors by offering a competitive return on capital invested.

Q. Does this rate case further the goals you just articulated?

A. Yes. The current case is necessary due primarily to the addition of two new generating plants, PW2 and Tucannon. Both plants are expected to come online in the first part of 2015 and we are filing this rate case to add them to customer prices when they do.[2]

PW2 is the resource chosen to meet the need for flexible capacity for peak customer demand and system balancing. We identified the need and the Commission acknowledged it in our 2009 IRP. PW2 will be highly efficient and responsive to load variation, ramping up to full load in less than ten minutes (as compared with about four hours for traditional natural gas fired plants).

Tucannon is the resource which will meet the IRP demonstrated need for 101 MWa of renewables to achieve Oregon's RPS that 15% of all large utilities' retail electric sales be met with qualifying renewable energy resources by 2015. Each plant was chosen after a rigorous process involving issuance of a Request for Proposals, review and scoring of bids,

[2] These plants are a result of the action plan implementation from PGE's 2009 IRP (updated in 2010, 2011 and 2012); while the specific projects were selected following a competitive RFP process in 2012, the need to bring these resources into our prices has been anticipated for some time.

and validation by an Independent Evaluator. The process and plants are more fully discussed in PGE Exhibit 400.

In summary, we are diligently working to bring these facilities online, on time, and on budget as they are essential to our providing safe, reliable electricity at a reasonable price and helping us meet Oregon's RPS.

Q. How does this rate case reflect your commitment to managing your costs?

A. This case reflects the savings achieved through our continuous improvement and efficiency efforts which are ongoing. As discussed in the next section, our adoption of continuous improvement cycles demonstrates our efforts to manage costs, streamline processes, learn from others, and create a continuous improvement culture at PGE.

III. Continuous Improvement Cycle

A. Overview

Q. In the previous section you stated your goals for PGE. Please elaborate on these goals as they relate to your strategic direction.

A. We are striving to deliver on our core business strategy by focusing on:

- Creating a positive safety culture;
- Keeping customer energy priorities our business focus;
- Ensuring PGE culture supports our objectives;
- Improving our operating efficiency in all aspects of our business;
- Maintaining plant and system availability while successfully executing on system investments;
- Improving our financial result; and
- Maintaining excellent stakeholder relationships.

Q. How does PGE hold business units accountable to these goals?

A. Accountability starts at the corporate level. Each year we develop corporate scorecard metric goals related to operational excellence that are focused on four key areas: high customer value, reliability and reasonably priced power, financial performance, and an engaged and valued workforce. These metrics measure PGE's operational excellence progress toward a stated goal. Our progress towards each goal is monitored quarterly. Each of these focused areas of accountability cascade down to functional areas and to individual business units. This alignment allows officers to monitor their areas of responsibility from their direct reports, to each manager and each employee as part of our continuous improvement cycle.

Q. Please explain PGE's continuous improvement cycle.

A. PGE's continuous improvement cycle is a constant and ongoing effort toward increasing our efficiency and effectiveness. Thus, after PGE functional units have identified and implemented improvements, the cycle begins again and we rotate through the organization searching for new efficiencies. PGE remains committed to its continuous improvement cycle and to becoming more efficient and effective in our day-to-day activities. The continuous improvement cycle aids PGE by helping each functional area understand how we compare to functional areas in similar companies, determine areas to strategically focus on and improve our operational efficiency and effectiveness.

Q. Is there a PGE department responsible for leading this effort?

A. Yes. The Corporate Performance Management group leads many of our efforts towards improvement, although not all. The expectation to drive for efficiency lies within all business units throughout PGE. Some of these business units have conducted their own "benchmarking" study because of less available common measureable data. Whether led by Corporate Performance Management or undertaken by the business unit, the common goal for all departments is to continuously improve operational efficiency. Benchmarking is used as a tool to analyze, plan and improve overall performance.

Q. Please explain the steps within the continuous improvement cycle.

A. The cycle consists of seven steps:

1. Perform data Collection;
2. Perform benchmarking[3] and best practice assessment;
3. Analyze and communicate results;

[3] This is not limited to just benchmarking. It could include other efforts such as Lean process improvement.

4. Build understanding and commitment for action;
5. Evaluate cost benefit and establish improvement goals;
6. Implement improvements; and
7. Monitor and revise as needed.

After the first cycle completes, another cycle is planned. Some departments are now beginning the second cycle of corporate benchmarking, such as Fleet, while others are still in the first cycle.

Q. Do all business units go through this standard cycle?

A. No. While some utility functions such as Information Systems and Customer Service have well established vendors that offer benchmarking services with reliable data and valid comparisons, other areas such as Corporate Communications and Public Policy are more difficult to benchmark due to less available common measureable data.

Q. How does PGE benchmark areas with less available data?

A. Certain functional areas independently conduct peer utilities' surveys to determine how similar functions operate and then identify improvements in their areas of responsibility.

Q. How long will this benchmarking effort go on?

A. PGE's continuous improvement process is an ongoing effort with results expected over multiple years. As we stated previously, there are several business units in varying stages of the benchmarking process at any given time. Although we do not expect large savings each and every year, we are striving for overall cumulative savings and will continue our effort for continuous improvement as part of PGE's Corporate Strategic Direction and Core Principles.

Q. What is PGE doing to manage the change occurring throughout the organization?

A. We have employed a Change Management Group to assist employees with the change process and to serve as the central resource to provide change management consulting services to facilitate change capability and readiness. Change Management is a structured approach to shifting and transitioning individuals, teams, and organizations from their current state to a desired future state. This in-house structure reduces third-party consultant fees. PGE's Change Management Group will create change competency and empower individuals, teams and organizations to embrace change in the current business environment.

B. Process Improvement Program

Q. Is benchmarking the only tool PGE is using to improve the efficiency and effectiveness of its operations?

A. No. There is no "one size fits all" solution for efficiency and improvement work; benchmarking is just one tool PGE employs. Some of PGE's other approaches include Lean reviews and business process analysis.

Q. What else is PGE doing to improve the efficiency and effectiveness of its operations?

A. PGE is currently planning to pilot a Process Improvement initiative during 2014. The program will pair education of process improvement methodologies with practical application through training and the implementation of improvement initiatives.

The expected value added by the proposed program would:

- Provide common tools that minimize inconsistency across improvement and efficiency work;
- Build internal capability and capacity, making PGE less dependent on external consultants;

- Train leaders to help facilitate culture and environment;
- Provide a central governance process to improve awareness and tracking of results in alignment with strategic priorities; and
- Reinforce a culture of improvement and best practice in employees' daily work and continuously monitoring and measuring results.

The program will be conducted using existing PGE resources including mentoring and leadership.

C. Update on Efficiencies

Q. Please describe the cost savings you have achieved.

A. In our previous general rate case, UE 262, PGE estimated that we would achieve approximately $15.6 million in cumulative efficiency savings through 2014. Since then, we have revised this estimate by $6.1 million and we now expect $21.7 million in efficiency savings through 2014. Table 1 below, summarizes expected efficiencies by functional area.

Table 1
Total O&M Savings
($ millions)

Business Unit	**UE 262 2014 Test Year**	**Revised Cumulative through 2014**	**Additions in 2015 Test Year**	**Cumulative through 2015 Forecast***
A&G	$1.1	$1.1	$0.0	$1.1
Finance	1.6	1.6	0.0	1.6
Human Resources	4.5	4.0	0.5	4.5
IT	5.0	9.7	0.0	9.7
T&D	3.4	4.1	0.3	4.4
Gov't Affairs/Public Policy	0.0	0.1	0.1	0.2
Customer Service	0.0	1.1	0.7	1.8
Total*	**$15.6**	**$21.7**	**$1.7**	**$23.4**

** May not sum due to rounding.*

Q. What do these savings represent?

A. Table 1 represents gross cumulative savings over a number of years, which reflect the facts that: 1) efficiency improvements can take time to realize; and 2) the functional areas are at different stages of the continuous improvement cycle, with some beginning the process earlier than others. In addition, the amounts above represent both hard savings and avoided costs.

Q. Please explain what you mean by "avoided costs."

A. Avoided costs are the costs that PGE would have incurred had we not found better solutions. Therefore, costs would have been higher had we not "avoided" them and found a more effective and less costly alternative.

Q. What are the total cumulative benefits projected by PGE through 2015?

A. PGE is projecting total cumulative savings and avoided costs of $23.4 million through 2015. Of this total $7.6 million (33 percent) is considered avoided cost savings. PGE Exhibit 707 (with the Corporate Support testimony), provides more detail regarding the components of the $23.4 million savings.

IV. Mitigation and Price Increase

Q. In the previous section you discussed your commitment to efficiency and continuous improvement and identified $23.4 million in cumulative savings. Is this a one-time amount or is it an annual amount?

A. The $23.4 million cumulative savings through 2015 represents an annual level of savings.

Q. As noted above, a portion of the $23.4 million savings consists of $6.1 million additional savings in 2014. How was your 2014 budget flat (as noted in Section II) given these additional savings?

A. The 2014 budget is within $1.6 million of the costs that are currently in PGE's retail rates, as approved by Commission Order No. 13-459. Other budgeted 2014 costs were known to increase, such as depreciation, which largely offset the additional $6.1 million savings. For additional details, see PGE Exhibit 300, Section I, B.

Q. What else have you done to reduce the price increase in this rate case?

A. As our business grows, we have worked hard to keep costs down to offset impacts of inflation. We took a number of specific actions including: 1) reducing our request related to incentive compensation costs, 2) asking to smooth effects of environmental remediation by spreading project costs over a longer period of time, and 3) updating our depreciation and line-loss studies. We also propose to refund excess funds in the Trojan Decommissioning Trust, due to the outcome of PGE's claim against the US Department of Energy, and Oregon Independent Spent Fuel Storage Installation (ISFSI) tax credits to further mitigate the price increase. The refunds are discussed in PGE Exhibit 300.

Q. What is the overall price increase that PGE is requesting in this proceeding?

A. With Commission approval of all elements of this filing, PGE cost of service and direct access customers would see an overall 4.6% increase in customer prices. The 4.6% includes PW2, Tucannon, and the refunds planned with regard to the Trojan Decommissioning Trust and ISFSI credits (PGE Schedule 143). Beginning in January 2015, cost of service and direct access customers will experience a price decrease of 0.9% with the increases going into effect as each of the two new plants enter service to total the overall increase of 4.6%.

V. Potential New Resource Acquisition

A. Boardman Co-ownership

Q. Is PGE negotiating with a Boardman Coal Plant co-owner to acquire its Boardman share?

A. Yes. Power Resources Cooperative (PRC), a 10 percent owner of the Boardman coal plant, is interested in selling its share to PGE. PRC is a cooperative corporation whose members are 13 Northwest retail electric distribution cooperatives, and none of its members take power from Boardman to load. At the time PRC negotiated a share of Boardman in 1976, the plant was under construction and PRC believed it had to secure generation to meet projected loads. PRC has no use for its share of the output and it no longer desires to be in the wholesale power generation supply business. PGE is interested in acquiring the 10% share, as long as the acquisition has a net zero or a beneficial impact to customers. More information is provided in PGE Exhibit 800.

Q. Has PGE and PRC reached agreement?

A. Not yet. Negotiations are pending. If agreement is reached, we will update this filing April 1, 2014.

B. Pelton-Round Butte Co-Ownership

Q. Is PGE negotiating a long-term contract with Confederated Tribes of the Warm Springs Reservation (Tribes) for the output of the Tribes' share of the Pelton/Round Butte and Re-Regulation Projects (Projects)?

A. Yes. PGE is negotiating with the Tribes for the Tribes to forego their right to sell the output of their one-third share of the projects on the market, and sell the energy and capacity output to PGE for ten years, starting January 1, 2015.

Q. What is your current agreement?

A. Historically, PGE has purchased the energy output from the Warm Spring Power and Water Enterprises (WSPWE – the Tribes' administering agency) on a year to year contractual basis with PGE's risk that WSPWE will exercise its right to sell its one-third share output on the market annually.

Q. Why is the current agreement changing?

A. WSPWE gave PGE notice of its intent to go to market and develop an auction process to sell the one-third share output to the highest bidder, as is their right under the operating agreement. As an alternative to WSPWE exercising this option, PGE and WSPWE have negotiated key terms for a multi-year agreement. Upon executing an agreement, PGE will update this filing. PGE Exhibit 500 provides more detail on negotiations and terms.

VI. Other Key Proposals

Q. Besides the addition of PW2 and Tucannon, what other key proposals are in this rate case?

A. Our case includes the following key proposals:

- Pricing changes:
    - Increase the residential customer charge by $1.00 per month and increase the small commercial (Schedule 32) customer charge by $1.00 per month for single phase and $2.00 per month for 3 phase service. The increase in the customer charge, albeit small, is to enable PGE to recover more of our fixed costs in the customer charges and reduce the recovery in the volumetric charges. Our approach is incremental. The small increase balances the need for greater fixed cost recovery, with the principle that the volumetric energy prices provide a signal for customers to use energy efficiently.
    - Approve new Schedule 143, Spent Fuel Adjustment, that passes along to customers, refunds from: 1) the US Department of Energy to the Trojan Nuclear Decommissioning Trust Fund related to the settlement of Trojan nuclear plant decommissioning expenses; and 2) Oregon Department of Energy payments related to state pollution tax credits for the Trojan Independent Spent Fuel Storage Installation (ISFSI). Schedule 143 will provide the approximately $50 million trust fund refund during a three year period, and the approximately $5.5 million ISFSI refund in one year.
    - Integrating the Schedule 90 load-following credit into the energy charge which would apply the credit to a Schedule 90 customer's entire load. The credit was

approved when the Commission accepted the stipulations in UE 262. Pricing changes are discussed in PGE Exhibit 1400.

- Inclusion of $1.5 million of capitalized costs associated with PGE's implementation and eventual participation in an Energy Imbalance Market (EIM), either a Northwest Power Pool market development initiative or the PacifiCorp and California Independent System Operator EIM. PGE is taking a leadership position in regional EIM efforts. The goal is greater reliability at lower cost. We expect to make our decision which, if either, to join by year end 2014. PGE Exhibit 800 discusses this further.
- An accounting order that allows PGE to mitigate and smooth the impact of the environmental remediation costs of the Downtown Reach, and later, Portland Harbor. This allows PGE to spread the incremental cost of the projects over twenty years to reduce the volatility of customer prices. PGE Exhibit 700 further describes the proposal.
- A major maintenance accrual for PW2 similar to the accrual for Port Westward 1 and Coyote Springs plants which is further discussed in PGE Exhibit 400.
- A forecasted capital structure of 50% equity and 50% debt to allow PGE to maintain our stable, investment grade credit rating, which will provide the financial strength necessary to make ongoing investment in our system, optimize the cost and access to capital markets, and provide access to wholesale fuel and power markets.
- An authorized return on equity of 10%, which is at the low end of the range recommended by our expert witness, Dr. Zepp, in PGE Exhibit 1200. Dr. Zepp's range is based on his sample using several methodologies. His recommended point estimate is 10.5%, which is above the sample average because PGE has more risk than the average utility in the sample. Our recommended 10% rate reflects PGE's request for accounting

orders and our desire to help mitigate the impact of increased costs given the slow recovery from the Great Recession in our service territory. The 10% rate, while below the recommended average estimated by Dr. Zepp, would still provide a fair investment opportunity for our shareholders, assuming the accounting orders are approved.

- Recovery of all costs and provision of all benefits related to renewable resources through the RAC consistent with ORS 469A.120. Doing so will provide PGE the opportunity to recover all prudently incurred costs and customers to receive all the benefits associated with PGE's RPS compliance. The current method of including renewables in the PCAM does not allow recovery of all such prudently incurred costs due to the workings of the PCAM. Our proposed change is discussed in more depth in PGE Exhibit 500.

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

A. Yes. The results of this case, as filed, will provide PGE with the opportunity to generate sufficient earnings and funds with which to meet its financial obligations as well as provide a fair opportunity for our shareholders.

VII. Structure of PGE's Filing

Q. How is PGE presenting this case?

A. PGE is presenting the following direct testimony:

- In Exhibit 200, Ham Nguyen, Senior Economist and Sarah Dammen, Economist, explain the process and method in forecasting the 2015 test year load forecast.
- In Exhibit 300, our project managers, Alex Tooman and Robert Macfarlane, summarize the overall 2015 test year revenue requirement, comparing the request with the 2014 approved prices in UE 262 and UE 266. This testimony also presents and uses, for test year purposes, PGE's request for new depreciation rates, based on the depreciation study before the Commission in UM 1679. It discusses the amortization of refunds related to Trojan decommissioning, PGE's rate base, the costs associated with PW2 and Tucannon, and how PGE proposes to include them in rates.
- In Exhibit 400 Maria Pope, Senior Vice President of Power Supply and Operations and Resource Strategy and Jim Lobdell, Senior Vice President, Finance, Chief Financial Officer and Treasurer, describe the new generation resources, Tucannon and PW2. In addition, the witnesses review the extensive planning and processes that led to the selection of the projects. Finally the joint testimony discusses the costs of the resources and PGE's progress to date to bring the projects on line, on time and on budget.
- In Exhibit 500, Managers Mike Niman, Terri Peschka, and Patrick Hager provide the initial forecast of PGE's Net Variable Power Costs (NVPC); discuss updates to parameters and modeling changes, comparing the forecast with the final 2014 NVPC forecast; and present PGE's proposal to "carve out" renewable resources from the PCAM,

passing those benefits and costs through PGE's Renewable Resource Automatic Adjustment Clause.

- In Exhibit 600, Arleen Barnett, Vice President of Administration and Jardon Jaramillo, Director of Compensation and Benefits, present PGE's compensation costs for the 2015 test year, efficiency gains, changes to compensation policies and plans, and proposed pension cost recovery.
- In Exhibit 700, Jim Lobdell, Senior Vice President, Finance, Chief Financial Officer and Treasurer, Cam Henderson, Vice President of Information Technology (IT), and Alex Tooman, Project Manager, explain PGE's costs and cost drivers related to corporate support operations including insurance, environmental services, business continuity and emergency management and Information Technology.
- In Exhibit 800, Stephen Quennoz, Vice President of Power Supply and David Weitzel, Analyst, Financial Analysis Group support PGE's O&M costs associated with PGE's long term power supply resources including plants and contracts. The joint testimony also discusses potential participation in an EIM, the PRC negotiations for sale of its Boardman share, recent plant performance and ongoing efforts to improve plant performance, reliability and safety.
- In Exhibit 900, Bill Nicholson, Senior Vice President of Customer Service, Transmission and Distribution and Bruce Carpenter, Vice President of Distribution, explain PGE's 2015 test year transmission and distribution O&M expenses and efficiencies.
- In Exhibit 1000, Kristin Stathis, Vice President of Customer Service Operations and Carol Dillin, Vice President of Customer Strategies and Business Development explain customer service O&M costs for the 2015 test year; provide an update on the Customer

Engagement Transformation project and fee free bankcard program; and discuss improvement initiatives.

- In Exhibit 1100, Patrick Hager, Manager of Regulatory Affairs, William Valach, Director of Investor Relations, and Brett Greene, Assistant Treasurer and Director of Treasury and Tax recommend PGE's cost of capital and capital structure for the 2015 test year.
- In Exhibit 1200 Thomas Zepp, economist, principal of Zepp Consulting LLC, and vice president of Utility Resources, Inc. estimates PGE's required return on equity and describes the analysis undertaken.
- In Exhibit 1300, Bruce Werner and Bonnie Gariety, both Pricing and Tariff analysts, describe marginal cost studies for distribution and customer service, respectively.
- In Exhibit 1400, Marc Cody, Senior Pricing Analyst, describes the marginal cost study for generation and demonstrates how the proposed tariff changes recover PGE's 2015 revenue requirement to achieve fair, just and reasonable prices for our customers. The testimony also discusses changes to various supplemental schedules and the new Schedule 143, Spent Fuel Adjustment.

VIII. 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 ratemaking. 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. I also serve on several community and business boards including LifeWorks Northwest, Greater Portland Inc., Oregon State University Foundation, the PGE Foundation, the Oregon Business Council, and the Edison Electric Institute.

Q. Mr. Lobdell, please describe your qualifications.

A. I received a Bachelor of Science degree from the University of Oregon in 1984. Since joining PGE in 1984 I have held a variety of positions at PGE and its affiliates including Vice President of Power Operations; Vice President, Risk Management, Reporting, and Control; Vice President of Portland General Distribution Company; Vice President of

Portland General Holdings II; Vice President of FirstPoint Utility Solutions; Manager of Financial Risk Management and Pricing at PGE; Treasurer of Tule Hub Services Company; Manger of Commercial Group Accounting for Portland General Holding; Project Manager for Columbia Willamette Development Company; and Supervisor of Accounting Operations for Portland General Corporation. I entered my current position as PGE Senior Vice President, Finance, Chief Financial Officer, and Treasurer in March 2013.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 283

Load Forecast

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Ham Nguyen
Sarah Dammen

February 13, 2014

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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 2015 test year forecast of 19,484 thousand megawatt-hours (MWh), 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 2015 forecast of total MWh deliveries takes into account the effect on demand of anticipated higher electricity prices in 2015 (compared to November 2013 base period prices) and savings from "incremental" energy efficiency (EE) programs that are funded through Schedule 109 Incremental Energy Efficiency Funding per Senate Bill 838 (SB 838).

There are two intermediate test year forecasts in addition to the final test year forecast. The three forecasts are referred to as the 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 final forecast is the E forecast, which specifically accounts for the savings from incremental EE programs. PGE Exhibits 201, 202, and 203 show the three detailed MWh delivery forecasts.

Q. How does the 2015 forecast compare to recent historical demand?

A. We forecast deliveries of 19,484 thousand MWh for the 2015 test year on a cycle-month (billing) basis to all customers. The 2015 test year deliveries are up from the 2013 weather adjusted actual deliveries of 19,265 thousand MWh by 219 thousand MWh, or roughly 1.1%.

Table 1 below summarizes the MWh delivery forecast in annual percentage changes by customer class from 2011 through 2015.

Table 1

Percent Change in MWh Delivery from Preceding Year: 2011-2015

Sector	2011	2012	2013	2014 (E)	2015 (E)
Residential	0.2%	0.4%	0.1%	-0.2%	-1.6%
Commercial	-0.4%	0.2%	-0.5%	1.1%	-0.3%
Manufacturing	6.1%	1.4%	1.0%	3.7%	3.0%
Miscellaneous	0.7%	3.5%	-1.5%	2.5%	-1.4%
Total Retail	1.3%	0.6%	0.1%	1.2%	-0.1%

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, MWh delivery in this case, to the percent change in “real” price. For the test year forecast, we first calculated the MWh 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 January 2015, we assumed a nominal price change of 3.3%, followed by a 2.3% price increase at the end of Q1, 2015 for both residential and non-residential customers. In 2014, we assumed nominal prices for residential customers to be 7.4% above November 2013 levels and for commercial customers 5.2% above November 2013. Inclusive of the 2014 price changes, we assumed the price at the end of Q1, 2015 to be 11% above November 2013 levels in "real" terms for residential customers and 8.9% above November 2013 levels in "real" terms for commercial customers, where November 2013 is the last historical data point.

Q. What price elasticity does PGE estimate and use in the forecast?

A. We used elasticity estimates of -0.1 for residential demand and -0.03 for nonresidential demand. The elasticities were derived from a "price" model that was re-estimated in September 2013 and remain essentially unchanged from previous estimates. A price elasticity of -0.1 means that if electricity prices rose an average of 10%, MWh demand would decline by 1%, all else equal. As we pointed out in UE 180, UE 197, UE 215, and UE 262 these elasticity estimates have remained stable since 2002 and are consistent with price elasticities estimated for the Northwest. Using these estimates of elasticity and the assumed price increases, the price-effect (P) forecast is about 248 thousand MWh or 1.2% lower than the base (B) forecast for 2015.

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. EE trends, including Senate Bill 1149 (SB 1149)[1] measures are assumed to be captured implicitly in the forecast model; therefore we made no explicit adjustments for these EE savings. The assumed incremental EE program levels incorporate new funding for EE programs beyond prior levels, starting in December 2013 the first month of the forecast. 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 nine cents per kWh for a cost-effectiveness upper limit, or an average levelized cost of 2.9 cents per kWh. We assumed these EE savings to have an effect beginning in December 2013. As stipulated in UE 262, PGE implemented a quarterly ramping of incremental EE savings to reflect the ETO's historic pattern of EE savings.

Q. How significant is the impact of incremental EE programs savings on PGE's delivery forecast?

A. We estimate a total of 314 thousand MWh or 1.6% savings from these programs in the 2015 test year based on the EE savings starting in December 2013 and accumulating through December 2015. PGE Exhibit 204 shows the savings from the incremental EE programs that are included in PGE's delivery forecast.

[1] Among other things, Oregon SB 1149 established the 3% public purpose charge to fund and encourage energy conservation.

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 is estimated using data from an extended historical period through October 2013. 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 are 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 fundamentally the same as that used in previous filings with the Commission. Past testimonies on the PGE load forecast describe 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 November power cost update filing for UE 266 (Load Forecast Work Papers) and UE 262 General Rate Case (PGE Exhibit 1300).

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 used Global Insight's November 2013 forecast, OEA's December 2013 forecast and the California EDD forecast from May 2013 to develop the MWh delivery forecast for this proceeding. These were the most current forecasts available at the time of the development 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 Group 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 based on the load forecast workshops stipulated in UE 262?

A. Yes. While the load forecast model framework and structure of our model remains essentially unchanged, we did take into account several of Public Utility Commission of Oregon Staff's suggestions made during the load forecast workshops stipulated in UE 262. These changes include re-estimation of the load forecast regression model with attention to the treatment of data outliers and updating the price elasticity equations.

Q. What assumption did you make regarding weather variables in the forecast?

A. We used the 15-year average weather observed from 1998 through 2012. 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 October 2013 for the residential equations and data from 1990 through October 2013 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 (MWh 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 MWh 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) MWh deliveries using their respective preceding-year ratios. We described in detail these sectors' model specifications and forecast processes in UE 180, UE 197, and UE 215 testimonies. The model specifications and forecast processes remain the same as those used in UE 262.

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 MWh 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 MWh 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 the 2015 test year, we apply updated line loss factors beginning in 2015. We use monthly voltage-level and system load factors to calculate the monthly peak MW based on the projected average MW. PGE Exhibit 210 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 2014 deliveries of 7,677 thousand MWh using the base model (B) and a forecast of 7,589 thousand MWh to 734,568 residential customers after accounting for the effects of price changes (P) and incremental EE programs (E). For the 2015 test year, we forecast deliveries of 7,743 thousand MWh (B) and 7,466 thousand MWh (E), respectively, to 740,049 residential customers. The assumed price increase and the incremental EE programs combine to reduce deliveries in 2015. These delivery levels reflect a 0.9% (B) and -1.6% (E) change from 2014 to 2015, compared to an actual 0.1% increase in MWh delivery, adjusted for weather, in 2013. Both forecasts include residential outdoor area lighting energy and the conversion of some of the residential outdoor area lighting to Light Emitting Diode (LED).

The forecasts include projections of 6,776 new residential connects in 2014 and 6,990 in 2015. The 2015 levels are above the total new residential connects of 6,843 in 2013 that includes actuals through November 2013 plus the December 2013 forecast and 5,592 connects in 2012. We forecast an increase of 0.8% in the number of residential customers in 2014, and 0.7% in 2015, compared to a 0.7% increase in 2013. PGE Exhibit 205 shows the forecast of building permits, new connects, and occupied accounts. PGE Exhibit 206 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 7,067 thousand MWh using the base (B) model and 6,991 thousand MWh after accounting for the effect of incremental

EE programs for 2014 (E). For the 2015 test year, we forecast deliveries of 7,190 thousand MWh in the base (B) forecast and 6,967 thousand MWh in the (E) forecast. As with residential customers, we expect rising electricity prices to have an impact on MWh 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 EE 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 and EE program savings, to increase 1.1% in 2014 and to decrease 0.3% in 2015. The growth in 2014 reflects the return to more historic growth after the decline in actual weather-adjusted delivery in 2013, while the 2015 forecast decline from the 2014 level reflects the reduction in demand due to the accumulation of EE savings as well as the price adjustments in both 2014 and 2015. Energy deliveries to this market segment, adjusted for weather, increased 0.2% in 2012 and decreased 0.5% in 2013.

PGE Exhibit 207 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 4,727 thousand MWh using the base model (B) and 4,707 thousand MWh after accounting for price and EE savings (E) for 2014. For the 2015 test year, we forecast deliveries of 4,909 thousand MWh (B) and 4,846 thousand MWh after accounting for the price adjustment and EE 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 EE programs. Test year deliveries (E) to industrial customers are projected to be 3.0% higher than the 2014 deliveries, which are forecasted at 3.7% higher than 2013 weather-adjusted deliveries. Manufacturing energy deliveries grew 1% in 2013 on a weather-adjusted basis. The manufacturing forecast reflects planned expansions by high-tech and related companies in our service territory. Deliveries to this market segment can show large swings from year to year due to specific individual company operations and industry conditions. PGE Exhibit 208 presents the detailed delivery forecast of the manufacturing sector.

PGE's manufacturing sector is concentrated in a few energy-intensive industries and large customers. In 2013, high tech industry accounted for over 43% of all manufacturing sector energy deliveries, the paper industry at roughly 20% 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 or market conditions or make other operational changes, 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 1% of total delivery to all retail customers in 2013. PGE Exhibit 209 shows 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 2013 year-end. Schedule 485/489 is the only service under which we forecast customers to receive direct access service in 2015. We pro-rate the COS and Schedule 485/489 deliveries by applying these customers' respective historical shares of service level or revenue class energy to the forecast. PGE Exhibit 211 shows the forecast of deliveries in 2015 to PGE COS customers and direct access (Schedule 485/489) customers.

Q. Do you recommend a specific forecast or forecasts of test year 2015 MWh delivery to end-use customers for ratemaking purposes?

A. Yes. We recommend the adoption of the E (post price and EE) forecast of 19,484 thousand MWh delivery to all customers.

V. Forecast Uncertainty

Q. How do you address MWh 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 2015 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 U.S. 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 MWh delivery forecast we submit in this filing is our "expected" or mid-point estimate. As such, it is a 50/50 "point" forecast, 50% 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 accuracy 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. In addition to examining strictly the in-sample period "fitness" of our model, we also evaluate and select final model specifications based on how well the model predicts recent actuals, a practice called out-of-sample testing.

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' operational decisions, new customers' entry or existing customers' exit and the absence of unforeseen natural disasters, wars or geopolitical turmoil. Future outcomes of these variables could result 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 November 2013 Global Insight and December 2013 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 November

2013 baseline U.S. economic forecast, 20% probability to its Low Scenario (Recovery Stalls) and 20% probability to its High Scenario (Recovery Reignites). For 2015, OEA (December 2013) forecasts Oregon total non-farm payroll employment to grow 2.2% from 2014 in its baseline case, up from 1.9% in 2013 and 2.1% in 2014 while bounded by -0.7% drop in the low (Mild Recession) case and 3.6% growth in the high (Optimistic) case. The OEA also presented a Severe Recession scenario that could lead Oregon payroll employment to contract 4.7% in 2015. 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 changed economic or specific circumstances. In fact, since the onset of the Great Recession in 2008 a number of large customers filed for bankruptcy, liquidated business, changed ownership or permanently shut down operations, which have substantially affected PGE's actual and anticipated MWh delivery. Specifically, in 2013 industrial deliveries were affected by the partial or full closure of paper manufacturers and decline in deliveries to solar manufacturing customers. With respect to announced new developments, we specifically include in this forecast planned expansions and operational changes by high-tech and paper manufacturing customers. If any of these assumptions fail to materialize, significant deviations from the test year forecast would result. While the forecast is developed to account for both upside potential (expansion) as well as downside risk, the inherent risks are biased toward the downside because it takes longer for a customer to plan and increase capacity than to shut it down.

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 MWh usage. PGE estimates that one degree variation in temperature could affect (total retail) MWh 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 equal, different economic outcomes result in delivery outcomes that differ from the initial forecast. The November 2013 Global Insight US forecast, in its baseline case, projects US GDP to grow 2.5% in 2014 and 3.1% in 2015, up from 1.7% in 2013 and U.S. non-farm payroll employment to increase 1.6% in 2014 and 1.8% in 2015, up from growth of 1.6% in 2013.

Similarly, the OEA baseline forecast used in the development of our load forecast is the December 2013 forecast, released in November of 2013. The OEA forecast anticipates Oregon payroll employment to continue growing at a relatively modest pace of 2.1% in 2014 and 2.2% in 2015, accelerating from 1.9% in 2013. Both forecasts were developed based on a number of assumptions including federal monetary policy changes in "tapering" of the Fed's bond buying program, no further federal spending sequestration and only modest repercussions from the federal government shutdown in October 2013. Though most indicators point to a continued period of economic expansion a number of risks to the forecasts exist. These risks include loss of momentum in the housing recovery due to higher interest rates, fiscal tightening, renewed sovereign-debt concerns in Europe, and weaker growth in emerging economies or another collapse of financial assets. Such outcomes would clearly lead to a significantly lower 2015 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 essential to PGE's forecast of MWh 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.

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 ECONorthwest, 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

Delivery Forecast (Base) by Market Segment and Service Level

(at average weather)

Base (not adjusted) Forecast (1)

	(in thousand MWh)					% Change (2)			
	2011	**2012**	**2013 (3)**	**2014**	**2015**	**2012**	**2013**	**2014**	**2015**
Schedule 7	7,565	7,594	7,601	7,672	7,739	0.4%	0.1%	0.9%	0.9%
Residential Lighting	7	7	7	5	4	0.0%	0.0%	-28.6%	-20.0%
Total Residential	7,572	7,600	7,608	7,677	7,743	0.4%	0.1%	0.9%	0.9%
Commercial	6,939	6,950	6,914	7,067	7,190	0.2%	-0.5%	2.2%	1.7%
Manufacturing	4,429	4,493	4,540	4,727	4,909	1.4%	1.0%	4.1%	3.9%
Miscellaneous Customers	198	205	202	207	204	3.5%	-1.5%	2.5%	-1.4%
Secondary Voltage	7,203	7,207	7,188	7,327	7,471	0.1%	-0.3%	1.9%	2.0%
Total General Service	7,401	7,412	7,390	7,534	7,676	0.1%	-0.3%	1.9%	1.9%
Primary Voltage Service	3,038	3,133	3,194	3,451	3,769	3.1%	1.9%	8.0%	9.2%
Transmission Voltage Service	1,126	1,102	1,073	1,017	859	-2.1%	-2.6%	-5.2%	-15.5%
Total Retail	19,138	19,248	19,265	19,679	20,046	0.6%	0.1%	2.1%	1.9%

1/ SDEC13B

2/ calculated from rounded numbers

3/ includes actual weather-adjusted values through December 2013

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, totals may not foot due to rounding.

Delivery Forecast (Price) by Market Segment and Service Level

(at average weather)

Net of Price Elasticity (1)

	(in thousand MWh)					% Change (2)			
	2011	2012 (3)	2013	2014	2015	2012	2013	2014	2015
Schedule 7	7,565	7,594	7,601	7,616	7,545	0.4%	0.1%	0.2%	-0.9%
Residential Lighting	7	7	7	5	4	0.0%	0.0%	-28.6%	-20.0%
Total Residential	7,572	7,600	7,608	7,621	7,549	0.4%	0.1%	0.2%	-0.9%
Commercial	6,939	6,950	6,914	7,059	7,160	0.2%	-0.5%	2.1%	1.4%
Manufacturing	4,429	4,493	4,540	4,721	4,885	1.4%	1.0%	4.0%	3.5%
Miscellaneous Customers	198	205	202	207	204	3.5%	-1.5%	2.5%	-1.4%
Secondary Voltage	7,203	7,207	7,188	7,315	7,426	0.1%	-0.3%	1.8%	1.5%
Total General Service	7,401	7,412	7,390	7,522	7,630	0.1%	-0.3%	1.8%	1.4%
Primary Voltage Service	3,038	3,133	3,194	3,449	3,761	3.1%	1.9%	8.0%	9.0%
Transmission Voltage Service	1,126	1,102	1,073	1,017	859	-2.1%	-2.6%	-5.2%	-15.5%
Total Retail	19,138	19,248	19,265	19,609	19,798	0.6%	0.1%	1.8%	1.0%

1/ SDEC13P

2/ calculated from rounded numbers

3/ includes actual weather-adjusted values through December 2013

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, totals may not foot 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 thousand MWh)					% Change (2)			
	2011	2012 (3)	2013	2014	2015	2012	2013	2014	2015
Schedule 7	7,565	7,594	7,601	7,584	7,463	0.4%	0.1%	-0.2%	-1.6%
Residential Lighting	7	7	7	5	4	0.0%	0.0%	-28.6%	-20.0%
Total Residential	7,572	7,600	7,608	7,589	7,466	0.4%	0.1%	-0.2%	-1.6%
Commercial	6,939	6,950	6,914	6,991	6,967	0.2%	-0.5%	1.1%	-0.3%
Manufacturing	4,429	4,493	4,540	4,707	4,846	1.4%	1.0%	3.7%	3.0%
Miscellaneous Customers	198	205	202	207	204	3.5%	-1.5%	2.5%	-1.4%
Secondary Voltage	7,203	7,207	7,188	7,240	7,214	0.1%	-0.3%	0.7%	-0.4%
Total General Service	7,401	7,412	7,390	7,447	7,418	0.1%	-0.3%	0.8%	-0.4%
Primary Voltage Service	3,038	3,133	3,194	3,442	3,741	3.1%	1.9%	7.8%	8.7%
Transmission Voltage Service	1,126	1,102	1,073	1,017	859	-2.1%	-2.6%	-5.2%	-15.5%
Total Retail	19,138	19,248	19,265	19,494	19,484	0.6%	0.1%	1.2%	-0.1%

1/ SDEC13E

2/ calculated from rounded numbers

3/ includes actual weather-adjusted values through December 2013

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, totals may not foot due to rounding.

Forecast of Incremental Energy Efficiency (EE) Savings

(in thousand MWh)

	2013 (1)	2014 (2)	2015
Base (B) Forecast	19,265	19,679	20,046
Price (P) Forecast	19,265	19,609	19,798
Incremental EE Savings (2)	-	(115)	(314)
Post-EE Forecast (E)	19,265	19,494	19,484

1/ 2013 MWh are weather-adjusted actuals through December 2013.

2/ Energy Trust of Oregon (ETO) annual savings deployment forecast.

Residential Building Permits, New Connects, Vacancy Rates and Occupied Accounts History and Forecast

	2011	2012 (1)	2013 (2)	2014	2015
Building Permits (3)					
Single-Family	5,241	6,675	8,792	9,462	9,648
Multi-Family	2,793	4,409	5,350	4,311	4,692
New Connects					
Single-Family	2,242	2,942	3,202	3,621	3,933
Multi-Family	1,112	2,604	3,605	3,119	2,996
Mobile Home	38	26	31	24	36
Other	21	20	5	12	24
Total Residential Connects	3,413	5,592	6,843	6,776	6,990
Vacancy Rates (%)					
Single-Family	4%	4%	4%	4%	4%
Multi-Family	7%	7%	7%	8%	8%
Mobile Home	8%	8%	8%	8%	8%
Number of Occupied Accounts					
Single-Family Heat	105,033	104,839	104,934	104,805	104,859
Single-Family Non-Heat	330,440	332,056	334,522	336,225	338,738
Multiple-Family Heat	160,948	161,667	164,084	163,540	164,127
Multiple-Family Non-Heat	51,191	51,910	52,905	53,446	54,599
Mobile Home Heat	28,159	28,076	28,052	27,878	27,684
Mobile Home Non-Heat	3,554	3,573	3,569	3,556	3,533
Other	5,105	5,029	4,933	4,890	4,855
Total Occupied Accounts	684,431	687,150	692,998	694,340	698,395
Total Number of Accounts (4)	720,056	723,440	728,481	734,568	740,049

1/ includes actuals through December 2013, except for building permits and connects which include actuals through November 2013.

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)

	2011 (2)	2012 (3)	2013	2014	2015
Use per Occupied Account (kWh)					
Single-Family Heat	15,878	15,935	15,795	15,759	15,299
Single-Family Non-Heat	10,845	10,803	10,782	10,669	10,483
Multiple-Family Heat	9,023	9,099	8,943	9,043	8,805
Multiple-Family Non-Heat	6,566	6,533	6,534	6,516	6,468
Mobile Home Heat	15,290	15,372	15,335	15,257	15,102
Mobile Home Non-Heat	11,488	11,495	11,623	11,453	11,346
Other	10,605	10,516	10,587	10,538	10,520
	-	-	-	-	-
Average Use per Occupied Account	11,054	11,051	10,968	10,922	10,686
Ultimate Deliveries (million of kWh)					
Single-Family Heat	1,668	1,671	1,657	1,652	1,604
Single-Family Non-Heat	3,584	3,587	3,607	3,587	3,551
Multiple-Family Heat	1,452	1,471	1,467	1,479	1,445
Multiple-Family Non-Heat	336	339	346	348	353
Mobile Home Heat	431	432	430	425	418
Mobile Home Non-Heat	41	41	41	41	40
Other	54	53	52	52	51
Schedule 7 Deliveries	7,565	7,594	7,601	7,584	7,463
Residential Lighting	7	7	7	5	4
Total Residential Deliveries	7,572	7,600	7,608	7,589	7,466

1/ SDEC13E

2/ weather-adjusted

3/ includes actual weather-adjusted values through December 2013.

Commercial Deliveries Forecast by NAICS Cluster

(at average weather)

Net of Price Elasticity and Incremental Energy Efficiency

	(in thousand MWh)					% Change (1)			
	2011	2012 (2)	2013 (3)	2014	2015	2012	2013	2014	2015
Food Stores	460	456	456	446	427	-0.9%	0.0%	-2.2%	-4.3%
Govt. & Education	999	988	977	980	982	-1.1%	-1.1%	0.3%	0.2%
Health Services	708	716	729	731	735	1.1%	1.8%	0.3%	0.5%
Lodging	106	107	105	105	103	0.9%	-1.9%	0.0%	-1.9%
Misc. Commercial	662	658	635	657	656	-0.6%	-3.5%	3.5%	-0.2%
Department Stores/Malls	340	345	347	346	345	1.5%	0.6%	-0.3%	-0.3%
Office & F.I.R.E. (4)	1,014	1,022	1,033	1,034	1,027	0.8%	1.1%	0.1%	-0.7%
Other Services	816	823	801	810	805	0.9%	-2.7%	1.1%	-0.6%
Other Trade	734	723	713	754	754	-1.5%	-1.4%	5.8%	0.0%
Restaurants	458	465	475	474	468	1.5%	2.2%	-0.2%	-1.3%
Trans., Comm. & Utility	642	646	642	656	664	0.6%	-0.6%	2.2%	1.2%
Total Commercial	6,939	6,950	6,914	6,991	6,967	0.2%	-0.5%	1.1%	-0.3%

1/ calculated using rounded-numbers

2/ includes actual weather-adjusted deliveries through December 2013

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 thousand MWh)					% Change (1)			
	2011	2012 (2)	2013 (3)	2014	2015	2012	2013	2014	2015
Food & Kindred Products	211	220	224	222	213	4.3%	1.8%	-0.9%	-4.1%
High Tech	1,860	1,915	1,941	2,093	2,363	3.0%	1.4%	7.8%	12.9%
Lumber & Wood	97	98	99	98	97	1.0%	1.0%	-1.0%	-1.0%
Primary & Fab. Metals	520	512	500	500	504	-1.5%	-2.3%	0.0%	0.8%
Other Manufacturing	624	652	681	734	739	4.5%	4.4%	7.8%	0.7%
Paper & Allied Products	938	916	926	889	757	-2.3%	1.1%	-4.0%	-14.8%
Transportation Equipment	180	181	168	171	173	0.6%	-7.2%	1.8%	1.2%
	-	-	-	-	-				
Total Manufacturing	4,429	4,493	4,540	4,707	4,846	1.4%	1.0%	3.7%	3.0%

1/ calculated using rounded-numbers

2/ includes actual weather-adjusted deliveries through December of 2013

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 thousand MWh)					% Change (1)			
	2011	2012	2013 (2)	2014	2015	2012	2013 (2)	2014	2015
Secondary (Residential)									
Outdoor Area Lighting (15R) (4)	7	7	7	5	4	-1.4%	0.0%	-25.0%	-27.5%
	0	0	0	0	0				
Secondary (Commercial)	0	0	0	0	0				
Outdoor Area Lighting (15C) (5)	16	16	16	14	12	-1.8%	-0.6%	-13.2%	-10.9%
Farm Irrigation et al. (6)	71	78	78	90	91	10.3%	-0.8%	15.7%	1.1%
Street and Other Lighting (7)	111	111	109	103	100	0.2%	-1.7%	-5.2%	-2.6%
Total Miscellaneous Commercial	198	205	203	207	204	3.6%	-1.2%	2.1%	-1.5%
All Miscellaneous Schedules (8)	205	212	209	212	207	3.5%	-1.2%	1.2%	-2.2%

1/ calculated from rounded numbers

2/ includes actual deliveries through December 2013

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 Schedule 95 beginning in 2013. Rate schedule 93 moved to Rate Schedule 38 in 2014

8/ equals line 2 + line 7

Total Delivery and Demand Forecast

(at average weather)

Net of Price Elasticity and Incremental Energy Efficiency

	Million kWh (1)	Average MW (2)	Peak MW (3)
2009	19,165	2,309	3,949
2010	18,893	2,283	3,582
2011	19138	2,316	3,555
2012	19248	2,319	3,597
2013	19265	2,339	3,869
2014	19,494	2,388	3,582
2015	19,484	2,366	3,537

1/ cycle-month basis, at end-user meters; includes actual deliveries through December 2013

2/ calendar basis, delivered to PGE's distribution system weather-adjusted actuals through December 2013

3/ coincidental annual system peak; includes actual through December 2013, not adjusted for weather.

4/ 2014 and 2015 are the price elasticity and incremental EE adjusted forecast.

Forecast of 2015 Deliveries to Cost of Service and Direct Access Customers

Net of Price Elasticity and Incremental Energy Efficiency

(in thousand MWh)

	Cost of Service	Direct Access (1)	Total Delivery (2)	
Residential	7,466	0	7,467	0.0%
Secondary	6,867	451	7,317	6.2%
Primary	3,013	727	3,741	19.4%
Transmission	526	333	859	38.8%
Lighting	100	0	100	0.0%
Total Retail (2)	17,973	1,511	19,484	7.8%

1/ Schedule 485/489 deliveries.

2/ Totals may not add due to rounding.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 283

Revenue Requirement

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Alex Tooman
Rob Macfarlane

February 13, 2014

Table of Contents

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. Macfarlane, 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 Robert Macfarlane. 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 2015 revenue requirements for the following components:

1. Base business
2. Port Westward 2 (PW2)
3. Tucannon River Wind Farm (Tucannon)

We separate these because both PW2 and Tucannon have expected on-line dates after January 1, 2015.

In addition to presenting these integrated or bundled revenue requirements, we also present and discuss our unbundled revenue requirements in Section IX.

Q. What increase in rates does PGE request on January 1, 2015 in this proceeding?

A. PGE requests a base business increase of $12.5 million or 0.7% effective January 1, 2015 before the consideration of the incremental effects of PW2 and Tucannon. The base business revenue requirement is $1,742.5 million on December 31, 2014 rate base of

$3,059.0 million. This increase is relative to the revenues we expect based on 2014 prices, which reflect approved rates in UE 262 and UE 266. This revenue requirement will allow PGE an opportunity to earn a 7.78% rate of return that includes a 10% return on average common equity (ROE) of 50% in 2015. PGE Exhibit 301, columns 1 through 3, summarizes the development of PGE's 2015 revenue requirement for PGE's base business.

Q. Are PW2 and Tucannon included in your request for $12.5 million of additional revenue?

A. No. As shown in PGE Exhibit 301, columns 4 through 9, we calculate that the incremental annualized revenue requirement increases related to PW2 and Tucannon are approximately $51.4 million and $46.7 million, respectively. PGE requests that the Public Utility Commission of Oregon (OPUC) authorize tariffs to collect these annualized amounts beginning with the on-line date of each respective generating plant. We currently expect PW2 to be on-line in the first quarter of 2015 and Tucannon to be on-line in the first part of 2015. To the extent that the on-line date for either plant changes, the effective date of tariffs to recover the incremental impact of the plant changes accordingly. In Section VII, we discuss the incremental revenue requirement of PW2; and in Section VIII, we discuss the incremental revenue requirement of Tucannon.

Q. How does PGE plan to collect the revenue associated with portions of Tucannon that become operational prior to the full plant on-line date?

A. PGE will make a filing on April 1, 2014 pursuant to Schedule 122 Renewable Resources Automatic Adjustment Clause to defer and collect the revenue requirement associated with the portions of Tucannon that become operational prior to the full plant on-line date.

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

A. Yes. As described in PGE Exhibit 100, we reduced the revenue requirement by: 1) removing or reducing incentive compensation costs; 2) keeping budgets flat to 2014 with limited exceptions, before applying escalations; 3) achieving savings from continuous improvements and efficiency efforts to improve operations in various parts of PGE as described in PGE Exhibit 100; and 4) updating our depreciation and line loss studies. We also propose: 5) to smooth effects of environmental remediation by spreading project costs over a longer period of time; and 6) refund excess funds in the Trojan Decommissioning Trust provided by the US Department of Energy and Independent Spent Fuel Storage Installation (ISFSI) Oregon tax credits.

Q. In addition to approving PGE's proposed 2015 revenue requirement, what else is PGE requesting in this case?

A. PGE requests that the Commission provide an accounting order that allows PGE to smooth the impact of the environmental remediation including Downtown Reach, and later, Portland Harbor. This allows PGE to spread the incremental cost of the projects over a longer period to help temper the volatility of costs and customer prices as compared to including them in the test year forecasts as they are expected to be incurred. PGE Exhibit 700 further describes this proposal.

We also request that the Commission approve changes to PGE's Schedule 122 Renewable Resources Automatic Adjustment Clause and Schedule 126 Power Cost Adjustment Mechanism so that we can use Schedule 122 to refund to or collect from customers variances in power costs and production tax credits (PTCs) for Renewable Portfolio Standard-compliant resources. PGE Exhibit 500 provides a more detailed description of the proposal.

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 2015?

A. As shown in column 1 of PGE Exhibit 301, without a rate increase we would expect PGE's ROE to be approximately 9.53% in 2015 before PW2 and Tucannon are on-line, lower than its authorized ROE of 9.75%. With the revenue requirement of the two plants included, PGE's ROE would be 6.62% without a rate increase.

B. Structure of the Case

Q. Does PGE's 2015 revenue requirement include the effect of any new generation resources?

A. Yes. This case includes the net revenue requirement of two generating resources, PW2 and Tucannon, whose revenue requirement we propose to affect prices as each plant comes on-line. PGE has also included forecasted expenditures for additional debt financing associated with the Carty base load plant, which is expected to be on-line in 2016.

Q. Please summarize PGE's 2015 revenue requirement prior to PW2 and Tucannon.

A. Table 1 below summarizes PGE's 2015 revenue requirement by major category and provides a comparison to the results in UE 262. We also list the PGE testimony that addresses the specific cost categories.

Table 1
(Revenue Requirement Summary in $millions)

Rev Req Category:	2014 UE 262/266	2015 Test Year	Exhibit	No.
Sales to Consumers	$1,725,521	$1,742,500	Rev Req	300
Other Revenue	$22,145	$23,521	Rev Req	300
NVPC	$621,725	$593425	Power Costs	500
Production O&M	$121,083	$136,575	Production	800
Transmission O&M	$12,150	$15,028	T&D	900
Distribution O&M	$93,824	$94,623	T&D	900
Customer Service	$73,193	$78,915	Customer Svc.	1000
A&G	$144,725	$154,863	Corp. Support	700
Depr. & Amort.	$273,468	$280,008	Rev Req	300
Other Taxes	$108,993	$110,593	Rev Req	300
Income Taxes	$64,994	$64,067	Rev Req	300
Operating Income	$233,510	$237,923	COC	1100
ROE	9.75%	10.00%	ROE	1200

Q. Have components of any of the above categories moved from one category to another?

A. Yes. The amortization of major maintenance accruals for the Coyote Springs and Port Westward natural gas fired generating plants appeared in amortization in UE 262. We followed FERC guidance to classify amortization with the specific functional category and reclassified $9.5 million for the amortization of major maintenance accruals from amortization account 407.3 to production O&M.

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 2015 revenue requirement?

A. We developed the 2015 revenue requirement based on PGE's 2014 budgets. The 2014 budgets are escalated to 2015 for inflation and adjusted (both increases and decreases) for known and measurable changes.

Q. What comparisons with the 2015 test year costs do you make in the testimonies generally?

A. We compare our forecast of 2015 test year costs to PGE's 2014 budget. The 2014 budget approximates the final UE 262/266 costs that are currently in PGE's retail rates, as approved by Commission Order No. 13-459. PGE's 2014 budget was then escalated to 2015 and updated for incremental costs that are discussed in the applicable testimonies (the primary costs being PGE's new generating resources – PW2 and Tucannon). We perform these comparisons because this rate case test year is only one year beyond that of UE 262, which had a 2014 test year.

Q. Did you perform a reconciliation of the 2014 budget to the 2014 general rate case (GRC) forecast?

A. Yes. We compared costs from the final stipulated revenue requirement in UE 262 with PGE's 2014 budget as listed in Table 2, below. In summary, the 2014 budget is within 0.19% of the aggregate final UE 262 costs.

Table 2
Compare 2014 GRC to 2014 Budget
($millions)

Revenue Requirement Category*	**2014 GRC**	**2014 Budget****	**Variance**
Other Revenue	(22,145)	(21,952)	193
Operation & Maintenance			
Total Fixed O&M	226,997	224,909	(2,088)
Other O&M	217,978	216,835	(1,143)
Total Operation & Maintenance	444,975	441,743	(3,231)
Depreciation & Amortization	273,468	276,009	2,541
Other Taxes / Franchise Fees	108,993	107,870	(1,123)
Subtotal	382,461	383,879	1,418
Totals	**805,291**	**803,671**	**(1,620)**
% Variance			**(0.19%)**

* Does not include net variable power costs or income taxes.
** Normalized to be comparable to the 2014 rate case, e.g., adjusted for SERP, MDCP, Incentives, etc.

Q. Why do the individual lines not equal if the UE 262 amounts are the basis for the 2014 budget?

A. The specific line items do not equal for the following reasons:

- Several of the larger stipulated adjustments in UE 262 were applied to a single income statement line for regulatory purposes (e.g., wage and salary, and IT adjustments). For budgeting purposes, PGE applied the adjustments to all operating areas.
- PGE identified some additional savings that were incorporated in the 2014 budget (see PGE Exhibit 100). Other costs were known to increase, such as depreciation, which largely offset these cost reductions.
- Certain costs are based on actuary tables such as employee health care and retained losses. As new reports are received, PGE updates those budgets accordingly.

As noted above, however, in aggregate the 2014 budget is within 0.19% of the 2014 GRC amount. This represents a variance of only $1.6 million compared to over $800 million in total costs.

Q. What rates did you use to escalate the 2014 budget to 2015?

A. We applied the following escalation rates to the 2014 budget:

- Non-officer labor – 3.3% effective March 1 for bargaining employees and April 15 for non-exempt and non-officer exempt employees.
- Officer labor – 3.5% effective April 15.
- Outside services (PGE cost elements (CE) 1502, 1602, 2200, 2300) – 2.6% effective January 1.
- Direct materials (CE 2101, 2110) – 1.4% effective January 1.
- Employee business expense (CE 2400, 2701) – 1.7% 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 August 2013. Wage escalation is based on the forecast of compensation costs described in PGE Exhibit 600.

Q. Did you adjust PGE's 2015 revenue requirement to reflect previous ratemaking decisions and other regulatory policies?

A. Yes. We made several regulatory adjustments, listed in Table 3 below.

Table 3
(Regulatory Adjustments in $millions)

Rev Req Category:	O&M	Rate Base
Retail Services	$(0.1)	$(0.1)
Charitable Contributions	$(1.1)	
State & Federal Lobbying	$(1.0)	
Memberships and Dues	$(0.2)	
MDCP	$(5.3)	
SERP	$(1.4)	
Image Advertising	$(0.8)	
Total Adjustments	$(9.9)	$(0.1)

Q. Please explain these regulatory adjustments.

A. Following is a brief summary:

- 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, UE 215, and UE 262;
- Managers Deferred Compensation Plan (MDCP): removed the entire $5.3 million from cost of service;
- Supplemental Executive Retirement Plan (SERP): removed the entire $1.4 million from cost of service;
- Corporate image advertising: removed the entire $0.8 million from cost of service.

II. Other Revenue

Q. What is PGE's 2015 forecast of Other Revenue and how does it compare with prior years?

A. PGE forecasts 2015 Other Revenue of $23.5 million. This compares to 2014 Other Revenue of $22.1 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 4 below.

Table 4
(Other Revenue in $millions)

Rev Req Category:	2014 UE 262	2015 Forecast
Utility Property Rental	$6.5	$7.0
Intertie/Other Transmission	$6.3	$6.5
Late Payment Interest	$2.6	$2.9
Steam Sales	$1.6	$1.8
Other Misc. Revenues	$5.1	$5.3
Totals	$22.1	$23.5

Q. Did you make any adjustments related to Other Revenue for the 2015 test year?

A. Yes. We adjusted the 2015 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 2015.

III. Depreciation

Q. What is PGE's estimate for 2015 depreciation expense?

A. We estimate $245.9 million in depreciation expense for the 2015 test year excluding PW2 and Tucannon. PGE Exhibit 303 summarizes the test year depreciation expense by plant type and provides a comparison to the 2014 forecast from UE 262.

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

A. Yes. PGE has filed the new depreciation study on December 5, 2013. It is docketed in UM 1679.

Q. What is the difference between the old depreciation study (UM 1458) estimate for 2015 depreciation expense and the new study estimate?

A. The difference is a decline of $2.2 million. Under the old depreciation study, PGE's forecast would be approximately $248.1 million.

Q. What are the primary drivers of this decrease?

A. The primary drivers are a $17.6 million decrease in distribution assets depreciation which is partially offset by increases of $6.7, $4.4 and $2.5 million in hydro assets, general plant and Port Westward depreciation.

Q. What depreciation expense was forecasted for 2014 in UE 262?

A. PGE's forecasted expense was $242.9 million calculated using the UM 1458 depreciation study.

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 2015 amortization expense.

A. PGE Exhibit 304 details the total 2015 amortization expense of $34.1 million, which we summarize in Table 5 below.

Table 5
(Amortization in $millions)

Amortization Item:	2014 Year	2015 Test Year
Software Amortization	$18.6	$26.8
Other Intangible Amortization	$3.2	$3.2
Trojan Decommissioning	$3.5	$3.5
Other Reg Debit Amortization	$11.4	$2.1
Other Reg Credit Amortization	$(5.9)	$(1.5)
Total Amortization	$30.8	$34.1

Q. Please explain the amortization of software included in PGE's 2015 amortization expense.

A. Total software amortization is $26.8 million, which represents the amortization of capitalized software, and is generally amortized over a 5 year period, but the 2020 Vision program will be amortized over 10 years.

Q. Why is software amortization $8 million higher in 2015?

A. The largest drivers for the increase are software additions for Maximo Wave II ($6.7 million) and IT Cyber Security Roadmap ($1.6 million).

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.

Q. Please describe the change in Other Regulatory Debits and Other Regulatory Credits.

A. Other Regulatory Debits decrease from 2014 to 2015 due to the reclassification of $9.5 million for the amortization of major maintenance accruals from amortization to production O&M. The decrease is partially offset by an increase of $0.3 million for energy imbalance market (EIM) and the reclassification of the Coyote Springs LTSA expense to production O&M. See PGE Exhibit 800 for a more detailed description of EIM.

Q. Did PGE make any changes to its Trojan Nuclear Decommissioning Trust (NDT) collection rate in its last general rate case (UE 262)?

A. No. PGE continues to collect $3.5 million in 2014 for the Trojan NDT.

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

A. Not at this time. In early 2013 we performed an analysis of the annual accrual, updated for the latest Trojan NDT balances, expected rate of return on trust assets, cost estimates, and other parameters. This analysis indicated that no change in the collection rate was needed. 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. Did PGE receive any damages from the US Department of Energy (DOE) as a result of its breach of contract lawsuit against the DOE?

A. Yes. PGE received approximately $44 million from the US DOE. The funds are currently held in the Nonqualified Fund of the Trojan NDT.

Q. Why did PGE receive damages from the US DOE?

A. PGE entered into a contract with US DOE on June 13, 1983. Part of the contract required PGE to pay DOE 0.1 cents for each kilowatt-hour of electricity that the Trojan plant produced. In return, DOE was required to take possession of the spent nuclear fuel generated at Trojan, beginning no later than January 31, 1998.

The DOE breached its contract with PGE by refusing to take possession of the spent nuclear fuel. To this date, the DOE continues to refuse to accept the spent fuel. PGE sued the DOE to recover the extra costs incurred (damages) as a result of the DOE's breach of contract. For example, due to the DOE's breach PGE was forced to build a dry storage facility. In addition, PGE has incurred, and continues to incur, additional spent fuel storage O&M costs.

PGE settled the lawsuit with the DOE last year. The settlement, which was approved by the court on July 18, 2013, resulted in partial reimbursement of costs incurred through the end of 2009 (approximately $70 million) for the Trojan partners. PGE's share was approximately $44 million.

Q. Is the Trojan NDT overfunded?

A. Yes. We examined the balance in the Trojan NDT and determined it is overfunded by $44 million. The study is included in our work papers. PGE seeks OPUC direction and permission to withdraw $44 million and refund that amount to customers.

Q. Is PGE likely to receive additional decommissioning levies from the US DOE?

A. Yes, we seek an additional $6 million.

Q. What does PGE propose to do with this amount?

A. Commencing in 2015, PGE intends to amortize the $44 million amount plus another $6 million over three years through Schedule 143 as described in PGE Exhibit 1400. If PGE doesn't receive the $6 million, we will simply decrease the refund by that amount in year three (2017). For modeling purposes we have assumed receipt and amortization of the full $50 million as shown in our work papers.

Q. What decommissioning activity is planned for 2014 and 2015?

A. The majority of the structures at the facility have been already demolished. PGE is preparing the Trojan North and Trojan Training buildings for decommissioning, and demolition is expected to take place during second quarter of 2014. Beyond this, PGE has no further planned decommissioning demolition work until after the spent nuclear fuel has been removed from the site.

V. Income Taxes, Taxes Other than Income

A. Income Taxes

Q. What is PGE's 2015 estimate of income taxes?

A. PGE's 2015 test period income tax expense forecast is $64.1 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 $65.0 million based on approved rates. The slight decrease in 2015 test year income tax expense compared to current rates reflects increased production tax credits from Biglow Canyon Wind Farm offset by increased tax expense due to a higher book taxable income reflected in this case.

Q. What methodology did you use to establish estimated income tax expense for the 2015 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. Further, since PGE's operations are nearly 100% regulated utility activity, this method also conforms to ORS 757.269

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 7.6%, 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 7.61%. 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 262?

A. Yes. In UE 262, the state composite tax rate was 7.47%. In this proceeding, we have adjusted the figure upward to 7.61% 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 39.95%. 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% + 7.61% - (35.00% * 7.61%) = 39.95%

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 2015?

A. Yes. We included $2.5 million of state Business Energy Tax Credits (BETC), $0.5 million of state pollution control tax credits not related to ISFSI, and $28.8 million of federal

National Environmental Policy Act (NEPA) credits in the estimate of 2015 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 wind energy forecast on a five-year average consistent with the wind energy forecast used for NVPC.

B. Taxes Other Than Income & Fees

Q. What is PGE's 2015 estimate of Taxes Other Than Income and Fees?

A. As shown in PGE Exhibit 306, total Taxes Other Than Income are $110.6 million. This compares to UE 262 2014 costs of $109.0 million. The individual sources of increased costs from 2014 to the 2015 test year are:

- Franchise Fees: from $43.2 million to $43.8 million;
- Payroll Taxes: from $13.6 million to $14.0 million; and
- Property Taxes: from $50.4 million to $51.1 million.

Franchise Fees

Q. How did PGE estimate franchise fees?

A. We evaluated the expected level of franchise fees based on estimated 2015 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%, identical to the rate of 2.501% authorized in UE 262.

Q. Why have franchise fees increased between current rates and the 2015 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 from 2014 to the 2015 test year?

A. Payroll taxes have increased generally in alignment with wage and salary growth between those years described in PGE Exhibit 600.

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 (Tucannon and 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, Montana, and Washington "centrally assess" PGE's property using a unit approach. This unit approach is required by state statutes because the properties are so thoroughly integrated that valuation of each individual asset would not equal the entire unit value. For example, 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)
<u>- Accumulated Depreciation/Amortization</u>
= 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 PGE. 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. The state then uses the Western States Association of Tax Administrators (WSATA) formula to calculate Oregon'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 Oregon.

Montana uses the WSATA formula similar to Oregon.

PGE has historically had little presence in Washington, and therefore, the three approaches to value were not used by that state. Washington previously valued PGE property in the state (percentage of KB Pipeline) using historical cost less depreciation of Washington's assets. With the addition of Tucannon, the valuation method is expected to be the same as the one currently used for KB Pipeline.

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 2013/2014 fiscal tax year, PGE disputed the original Oregon assessed value of approximately $4 billion and was able to receive a reduction of $300 million in assessed value. Also, PGE was able to reduce its 2013 Montana assessed value by $6.7 million, which resulted in a $0.1 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 through 2013) 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 in the annual report. 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 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, 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 for PGE's Carty and PW2 plants that are currently under construction.

Q. Does the 2015 estimate of Port Westward 2 property tax expense reflect the benefit of the SIP agreement with Columbia County?

A. Yes. With the SIP agreement with Columbia County, we expect first year property tax expense for PW2 of $1.4 million. Without the SIP, a full year of property tax expense related to would be approximately $4.4 million.

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, 2013, Oregon assessed value was $3.5 billion. PGE net book value of utility plant (per 2012 FERC Form 1) was $3.5 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, 2013 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. Because Oregon property taxes are assessed on a fiscal year basis, assessed values at January 1, 2014 and 2015 have to be calculated. Starting with the latest actual assessed value for each state, PGE adds an estimate for projected capital expenditures and associated increases in accumulated depreciation.

Q. After estimated assessed value is calculated, what is the next step to determine 2015 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 2013/2014, county property tax rates range from less than 1% up to 2% of assessed value with a weighted average of 1.349%. For Montana, 2013 county property tax rates averaged approximately 3.523%. 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 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 2015 property taxes?

A. PGE's forecast of 2015 property taxes is $51.1 million excluding PW2 and Tucannon, an increase of $0.7 million from 2014.

Q. What are the primary reasons why property taxes will increase from 2014 to 2015?

A. The estimated property tax expense increase from $50.4 million in 2014 to $51.1 million in 2015 is primarily due to an anticipated allowed inflation of 3% for Oregon.

VI. Rate Base

Q. What is PGE's 2015 rate base and what does it include?

A. The 2015 rate base excluding PW2 and Tucannon is $3,059 million based on projected rate base as of December 31, 2014. PGE Exhibit 307 provides the details of the 2015 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 rate base includes Fuel and Materials Inventory, Miscellaneous Deferred Debits and Credits, and Working Cash.

Q. How does PGE's 2015 rate base compare to rate base amounts approved in UE 262?

A. PGE Exhibit 308 shows that the rate base approved in UE 262 is $3,054 million. PGE's rate base is nearly flat, increasing by $5 million to $3,059 million.

Q. How did you develop the estimate of plant in service for the 2015 test year?

A. We calculate rate base at December 31, 2014. First, we estimated year-end 2013 embedded plant using actual results as of the end of the third quarter with forecasted closings through year-end. Next, we evaluated 2014 capital additions. Certain larger projects were closed based on specific forecasted closing dates. For example, we forecast the surface collector at River Mill to close by December 31, 2014.

However, we model most capital additions by evaluating CWIP balances using historical experience. We then apply a forecast closing pattern to CWIP to develop plant-in-service estimates from 2014 capital additions. We don't include 2015 plant additions. Our work papers detail the development of 2015 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. No.

Q. Does PGE propose a new lead-lag study to update working cash?

A. No. PGE uses the UE 262 working cash factor of 3.7% for the 2015 test year.

Q. What is the working cash total added to rate base in this filing?

A. Applying the 3.7% working cash factor to total forecasted operating expenses in 2015 of $1,528 million yields the working cash addition to rate base of $56.5 million, which is shown in PGE Exhibit 301.

VII. Port Westward 2

Q. What is the annual revenue PGE requires as a result of the addition of PW2?

A. As shown in PGE Exhibit 301 column 5, PGE requires an additional $51.4 million annually for PW2's expected operating costs, net of dispatch benefits, as well as to provide a reasonable return on investment.

Q. How did you estimate the operating costs of PW2?

A. We estimated the operating costs on an annualized basis, reflecting the first full year of operations. PW2's O&M costs of $1.8 million and depreciation expense of $13.6 million reflect a full year's costs.

We derived the dispatch benefits of PW2 by taking the dispatch benefits for full year 2015.

Finally, rate base of $305 million for PW2 reflects an average balance over the first full year of operation.

Q. Does PGE include property taxes associated with PW2 in the annual revenues required for PW2?

A. Yes. Property taxes for PW2 amount to $1.4 million in 2015. This includes the effect of the SIP property tax abatement executed with Columbia County.

Q. Do you propose a major maintenance accrual for PW2?

A. Yes. PGE proposes a major maintenance accrual for PW2 based on the projection of LTSA expenses and other major maintenance or inspections not covered by the LTSA. PW2's major maintenance contract is described further in PGE Exhibit 400. We propose a levelized amortization amount of approximately $1 million that collects those projected expenses over a period of five years. The major maintenance accrual will help smooth the lumpy nature of these costs and result in better matching of cost with revenue. This will also reduce the frequency of rate changes by eliminating the need for an annual true-up and prevent excessive over- or under-collection for LTSA and maintenance expenses, ensuring that customers only pay for costs incurred.

Q. Is PGE requesting rates to recover PW2 costs effective January 1, 2015?

A. No. As explained in PGE Exhibit 1400, we are requesting rates effective with the on-line date of PW2. The annualized fixed costs of PW2 should only be minimally affected by the on-line date (e.g., monthly inflation on O&M) and are likely immaterial for small changes in the on-line date.

VIII. Tucannon River Wind Farm

Q. What is the annual revenue PGE requires as a result of the addition of Tucannon?

A. As shown in PGE Exhibit 301 column 8, PGE requires an additional $46.7 million annually for Tucannon's expected operating costs, net of dispatch benefits, as well as to provide a reasonable return on investment.

Q. How did you estimate the operating costs of Tucannon?

A. We estimated the operating costs on an annualized basis, reflecting the first full year of operations. Tucannon's O&M costs of $8.9 million and depreciation expense of $23.7 million reflect a full year's costs.

We derived the dispatch benefits of Tucannon by taking the dispatch benefits for the first nine months of operations (i.e., April 1, 2015 through December 31, 2015) and annualizing them based on PGE's load shape.

Finally, rate base of $494 million for Tucannon reflects an average balance over the first full year of operation.

Q. Do you include federal tax credits in your annual revenue requirement for Tucannon?

A. Yes. We include $19.8 million of NEPA credits in the estimate of 2015 test year income tax expense for the addition of Tucannon.

Q. Is PGE requesting rates to recover Tucannon costs effective January 1, 2015?

A. No. As explained in PGE Exhibit 1400, we are requesting rates effective with the on-line date of Tucannon, which we expect to be in the first half of 2015. For purposes of calculating dispatch benefits, we used an on-line date of April 1, 2015. If the on-line date of Tucannon changes, we propose updating the estimate of dispatch benefits to reflect the annualized dispatch benefit beginning with the assumed on-line date. The annualized fixed costs of Tucannon should only be minimally affected by the on-line date (e.g., monthly inflation on O&M) and are likely immaterial for small changes in the on-line date.

Q. If some wind turbines come on-line before the full plant is on-line, how is PGE requesting to recover Tucannon costs?

A. We will separately file to recover costs through Schedule 122 Renewable Resources Automatic Adjustment Clause. When the plant is fully on-line, the revenue requirement described above for Tucannon will become effective through base rates.

IX. Unbundling

Q. Have you unbundled the 2015 revenue requirement pursuant to OAR 860-038-0200?

A. Yes. PGE Exhibit 309 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 2015.

Table 6
(Unbundled Revenue Requirement - $millions)

Production	$1,035.7
Transmission	35.4
Distribution	551.3
Metering	2.5
Billing	57.5
Other Consumer Services	55.3
Ancillary Services	4.9
Public Purposes	Collected by separate tariff
Total	**$1,742.5**

The sum of the unbundled revenue requirement for these services equals the integrated revenue requirement as presented in PGE Exhibit 301 columns 1 through 3.

The total unbundled revenue requirement including PW2 and Tucannon is presented in Exhibit 310.

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 2015 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 6 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 write-offs for uncollectibles directly to the distribution function.

X. 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. Macfarlane, please state your educational background and experience.

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. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
301	2015 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
307	Summary of Rate Base
308	Reasons for Changes in Rate Base since UE 262
309	Base Unbundled Results of Operations Summary
310	Total Unbundled Results of Operations Summary

PGE Exhibit 301
2015 Results of Operations
Increase in Base Rates Needed for Reasonable Return
Dollars in (000s)

	Base Business			Base Business and PW2			Base Business and Tucannon			Total
	2015 Results at 2014* Base Rates	Change for Reasonable Return	2015 Results After Change for Reasonable Return	2015 Results at 2015 Base Rates	Change for Reasonable Return	2015 Results After Change for Reasonable Return	2015 Results at 2015 Base Rates	Change for Reasonable Return	2015 Results After Change for Reasonable Return	2015 Results
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Operating Revenues										
Sales to Consumers (Rev. Req.)	1,730,004	12,496	1,742,500	1,742,500	51,371	1,793,870	1,742,500	46,663	1,789,163	1,840,533
Sales for Resale	-	-	-	-	-	-	-	-	-	-
Other Operating Revenues	23,521	-	23,521	23,521	-	23,521	23,521	-	23,521	23,521
Total Operating Revenues	1,753,525	12,496	1,766,021	1,766,021	51,371	1,817,391	1,766,021	46,663	1,812,683	1,864,054
Operation & Maintenance										
Net Variable Power Cost	593,425	-	593,425	592,212	-	592,212	577,002	-	577,002	575,789
Operations O&M	246,227	-	246,227	247,706	-	247,706	254,700	-	254,700	256,179
Support O&M	233,676	102	233,778	234,125	417	234,542	234,212	379	234,592	235,356
Total Operation & Maintenance	1,073,328	102	1,073,430	1,074,042	417	1,074,460	1,065,915	379	1,066,294	1,067,324
Depreciation & Amortization	280,008	-	280,008	293,596	-	293,596	303,679	-	303,679	317,267
Other Taxes / Franchise Fee	110,280	313	110,593	112,056	1,285	113,341	117,544	1,167	118,711	121,459
Income Taxes	59,242	4,824	64,067	54,419	19,833	74,252	29,569	18,016	47,585	57,770
Total Oper. Expenses & Taxes	1,522,859	5,238	1,528,097	1,534,113	21,535	1,555,649	1,516,707	19,562	1,536,269	1,563,820
Utility Operating Income	230,666	7,257	237,923	231,907	72,906	261,742	249,314	66,224	276,415	300,234
Rate of Return	7.542%		7.779%	6.893%		7.779%	7.017%		7.779%	7.778%
Return on Equity	9.526%		10.000%	8.230%		10.000%	8.478%		10.000%	10.000%

* 2014 Rates per approved UE 262 and UE 266

PGE Exhibit 301
2015 Results of Operations
Increase in Base Rates Needed for Reasonable Return
Dollars in (000s)

	Base Business			Base Business and PW2			Base Business and Tucannon			Total
	2015 Results at 2014* Base Rates	Change for Reasonable Return	2015 Results After Change for Reasonable Return	2015 Results at 2015 Base Rates	Change for Reasonable Return	2015 Results After Change for Reasonable Return	2015 Results at 2015 Base Rates	Change for Reasonable Return	2015 Results After Change for Reasonable Return	2015 Results
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Rate Base										
Plant in Service	7,293,364	-	7,293,364	7,603,781	-	7,603,781	7,803,401	-	7,803,401	8,113,818
Accumulated Depreciation	(3,805,842)	-	(3,805,842)	(3,812,518)	-	(3,812,518)	(3,817,676)	-	(3,817,676)	(3,824,352)
Accumulated Def. Income Taxes	(579,549)	-	(579,549)	(574,257)	-	(574,257)	(631,267)	-	(631,267)	(625,975)
Accumulated Def. Inv. Tax Credit	-	-	-	(3,835)	-	(3,835)	48,058	-	48,058	44,222
Net Utility Plant	2,907,972	-	2,907,972	3,213,170	-	3,213,170	3,402,515	-	3,402,515	3,707,713
Misc Deferred Debits	30,852	-	30,852	30,852	-	30,852	30,852	-	30,852	30,852
Operating Materials & Fuel	75,103	-	75,103	75,103	-	75,103	75,103	-	75,103	75,103
Misc. Deferred Credits	(11,740)	-	(11,740)	(11,740)	-	(11,740)	(11,740)	-	(11,740)	(11,740)
Working Cash	56,346	194	56,540	56,762	797	57,559	56,118	724	56,842	57,861
Total Rate Base	3,058,533	194	3,058,727	3,364,147	797	3,364,944	3,552,848	724	3,553,572	3,859,789
Income Tax Calculations										
Book Revenues	1,753,525	12,496	1,766,021	1,766,021	51,371	1,817,391	1,766,021	46,663	1,812,683	1,864,054
Book Expenses	1,463,617	414	1,464,031	1,479,694	1,702	1,481,397	1,487,138	1,546	1,488,684	1,506,050
Interest Rate Base @ Weighted Cost of Debt	84,981	5	84,987	93,473	22	93,495	98,716	20	98,736	107,244
Production Deduction	-	-	-	-	-	-	-	-	-	-
Permanent Sch M Differences	(20,679)	-	(20,679)	(20,679)	-	(20,679)	(20,679)	-	(20,679)	(20,679)
Temporary Sch M Differences	(26,469)	-	(26,469)	(26,469)	-	(26,469)	(26,469)	-	(26,469)	(26,469)
State Taxable Income	252,074	12,076	264,151	240,001	49,646	289,647	227,315	45,096	272,411	297,908
State Income Tax	16,183	919	17,103	15,264	3,780	19,044	14,298	3,434	17,732	19,673
Federal Taxable Income	235,891	11,157	247,048	224,737	45,866	270,603	213,017	41,663	254,679	278,235
Fed Income Tax	82,562	3,905	86,467	78,658	16,053	94,711	74,556	14,582	89,138	97,382
Deferred Taxes	(10,574)	-	(10,574)	(10,574)	-	(10,574)	(10,574)	-	(10,574)	(10,574)
Federal Tax Credits	(28,929)	-	(28,929)	(28,929)	-	(28,929)	(48,711)	-	(48,711)	(48,711)
Total Income Tax	59,242	4,824	64,067	54,419	19,833	74,252	29,569	18,016	47,585	57,770

PGE Exhibit 301
General Rate Case - 2015 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%	5.557%	2.779%
Total	N/A	100.00%		**7.779%**

Revenue Sensitive Costs:	
Revenues	1.000000
OPUC Fees	0.003125
Franchise Fees	0.025012
O&M Uncollectibles	0.005000
State Taxable Income	0.966863
State Tax @ 6.24%	0.073616
Federal Taxable Inc.	0.893248
Federal Tax @ 35%	0.312637
Total Income Taxes	**0.386252**
Total Rev. Sensitive Costs	**0.419389**
Utility Operating Income	0.580611
Net To Gross Factor	**1.722323**

RSC Gross-Up Factor 1.0343

State Income Tax:

	Appor	Rate	Weighted
Montana	3.17%	6.75%	0.214%
Washington			0.000%
California	1.75%	8.84%	0.154%
Oregon	95.33%	7.60%	7.245%
State			7.614%

Composite Tax Rate: **39.949%**

Check:	Fed Tax	35.00%
	State Tax	7.614%
	Tax Shield	-2.66%
	Composite	39.949%

PGE Exhibit 302
Other Revenue Detail
2011 - 2015 Test Year

Account	Description	2011 Actuals	2012 Actuals	2013 (9+3)	2014 Forecast	2015 Test Year	
4560007	OthElecRev-TransmissionResale	$ (6,275,911)	$ (5,296,820)	$ (3,902,280)	$ -	$ -	
4560008	OthElecRev-Gas for Resale	$ (276,006)	$ 121,227	$ (2,850,010)	$ -	$ -	
4560010	OthElecRev-TransmissionRevElim	$ (18,846)	$ (31,610)	$ (23,670)	$ -	$ -	
4560011	Oil For Resale Revenue	$ (12,189)	$ -	$ -	$ -	$ -	
Group 1: Power Cost Items - Not include in rev req		$ (6,582,951)	$ (5,207,204)	$ (6,775,960)	$ -	$ -	
4470003	SalesfrResale-IntertiePGEtoPGE	$ (2,593,028)	$ (2,863,032)	$ (3,234,388)	$ (3,455,000)	$ (3,513,735)	
5660002	TransOp-MiscExp-IntertieWhePGE	$ 2,593,028	$ 2,863,032	$ 3,234,388	$ 3,455,000	$ 3,513,735	
Group 2: Intracompany transaction - PGE merchant purchase of intertie capacity from PGE transmission		$ -	$ -	$ (0)	$ -	$ (0)	
5660003	TransOp-MiscExpNonInterPGE-PGE	$ 46,530,461	$ 47,636,177	$ 48,612,370	$ 46,026,000	$ 46,808,442	
5660004	TranOp-MiscExpNonIntRevPGE-PGE	$ (46,530,185)	$ (47,636,177)	$ (48,612,372)	$ (48,092,215)	$ (48,909,783)	
Group 3: Intracompany transaction - PGE charging itself to wheel across our service territory		$ 275	$ -	$ (1)	$ (2,066,215)	$ (2,101,341)	
5470001	OthGenOp-Fuel-PGE RevKBP Reser	$ (2,066,215)	$ (2,066,215)	$ (516,550)	$ -	$ -	
5470002	OthGenOp-Fuel-KBP Month Reser	$ 2,066,215	$ 2,066,215	$ 516,554	$ 2,066,215	$ 2,101,341	
Group 4: Intracompany transaction - PGE charging itself for KB pipeline capacity		$ -	$ -	$ 4	$ 2,066,215	$ 2,101,341	
4500001	Forefeited Discounts	$ (1,854,756)	$ (2,587,422)	$ (2,750,748)	$ (2,900,000)	$ (2,900,000)	
4510001	Miscellaneous Service Revenues	$ (2,351,445)	$ (2,303,654)	$ (1,965,974)	$ (1,707,055)	$ (1,999,009)	
4530001	Sales of Water & Water Power	$ 17,839	$ (4,641)	$ (21,005)	$ -	$ -	
4540001	Rent From Electric Property	$ (1,797,125)	$ (1,707,745)	$ (1,543,236)	$ (1,307,175)	$ (1,307,411)	
4540002	RentFrElecProperty-Joint Pole	$ (4,966,741)	$ (5,698,892)	$ (5,169,353)	$ (5,739,806)	$ (5,739,806)	
4560001	Other Electric Revenues	$ (4,752,816)	$ (3,838,937)	$ (2,973,118)	$ (2,402,835)	$ (3,064,835)	
4560003	OthElecRev-FishWildlifeRecrOps	$ (17,976)	$ (11,508)	$ (16,006)	$ -	$ (16,594)	
4560004	OthElecRev-SSHG	$ (229,099)	$ (229,201)	$ (174,696)	$ (220,000)	$ (174,684)	
4560005	OthElecRev-Utility Non-Kwh	$ (34,396)	$ (654)	$ (30,801)	$ -	$ -	
4560012	OthElecRev-Steam Sales	$ -	$ (1,055,581)	$ (1,842,211)	$ (1,195,741)	$ (1,833,767)	
4561001	TransRevOthers-Non-Intertie	$ (1,565,735)	$ (1,840,168)	$ (2,137,727)	$ (1,980,392)	$ (1,361,291)	
4561002	TransRevOthers-Intertie	$ (4,502,711)	$ (5,413,152)	$ (5,290,943)	$ (5,110,000)	$ (5,110,000)	
5600003	TransOp-IntercoTransStudyRev	$ (151,992)	$ (5,091)	$ (5,308)	$ -	$ -	
Group 5: Remainder		$ (22,206,953)	$ (24,696,646)	$ (23,921,126)	$ (22,563,005)	$ (23,507,397)	
						$ (13,225)	SunWay
						$ (23,520,622)	Total

PGE Exhibit 303
Depreciation Detail ($000s)
2011 - 2015 Test Year

Property Group	2011 Actual	2012 Actual	2013 Actual	2014 Forecast	2015 Forecast	
Boardman	12,038	19,631	21,304	24,982	28,812	
Colstrip	4,800	4,906	4,861	5,262	5,758	
Beaver	3,766	3,573	3,659	3,914	4,847	
DSG	321	346	511	1,033	495	
Biglow Canyon	40,047	38,298	36,618	35,030	33,534	
Coyote Springs	4,221	5,052	4,912	4,689	5,390	
Port Westward	7,007	6,820	6,650	6,611	9,163	
Hydro	11,681	12,418	11,207	12,579	18,924	
Transmission	8,935	9,606	9,818	9,682	9,837	
Distribution	108,191	111,530	113,993	116,349	101,066	
General Plant	16,575	18,567	21,342	24,904	32,457	
Total	217,582	230,747	234,875	245,035	250,283	
					(4,775)	Remove Boardman Decomm
					(78)	Retail Adj.
					79	SunWay
					245,509	Total

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 Boardman forecasted depreciation includes effects of the Schedule 145 Tariff update, which incorporates the site specific decomissioning study with additional retention program.
2014 forecasted depreciation excludes coal car depreciation of 261 and vehicle depreciation of 4,214.

2015 Boardman forecasted depreciation includes effects of the Schedule 145 Tariff update, which incorporates the site specific decomissioning study with additional retention program and additional 15% ownership of non-coal handling assets.
2015 forecasted depreciation excludes coal car depreciation of 261 and vehicle depreciation of $3,516.

PGE Exhibit 304
Amortization Detail ($000s)
2011 - 2015 Test Year

Item	FERC Account	AWO	2011 Actual	2012 Actual	2013 Actual	2014 Forecast	2015 Forecast
Equity Issuance Fees	4&&		1,721,800	1,721,800	1,721,800	1,315,900	
Port Westward Major Maint. Accrual	4&&					4,946,816	
Remove Boardman Decomm (to Sch. 145)	4&&					1,512,747	1,454,304
Def Tax Asset Amortization	4&&					237,796	
Software Amort (Intangible)	404.0		13,178,424	17,305,027	18,987,419	18,603,446	26,774,747
Other Intangible Amort (includes Hydro Relicensing)	404.0		6,097,457	5,836,639	3,067,447	3,175,877	3,203,075
Boardman Decommissioning- UE215	407.3	3000000185	(431,270)	(462,960)	(462,960)	(490,598)	(519,840)
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	85,479		
Gain on Asset Sales, UE115	407.3	7000000317					
Accumulated ARO Boardman	407.3	7000000236	(1,064,421)	(1,025,518)	(1,355,455)	(1,022,149)	(934,464)
Coyote Springs Major Maintenance	407.3	7000000322	2,044,272	2,044,272	2,044,272	4,411,753	
ISFSI Tax Credits	407.3	7000000323	2,592,331	2,274,749			
Accelerated Depreciation- Old Meters	407.3	7000000351					
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					
2011 Local 408/MCBIT Deferral	407.4	3000000135		(604,940)			
Interest Income PES Note	407.4	7000000319		(266,032)	(16,606)		
Coyote Springs Major Maintenance	407.4	7000000322	(3,737,959)	(3,886,965)			
Sunway 3	407.4	7000000727	(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)	(16,966,496)		
Trojan Decommissioning	407.0	7000000045	3,500,278	3,500,175	3,500,000	3,500,000	3,500,000
EIM	4&&						300,000
Gain from Property Sales	411.6						
Independent Evaluator Deferral	407.3	7000000123			297,920		
FiT Pilot Program	407.3	7000002001		4,896,926	4,997,432		
Coyote Springs GE LTSA Exp	407.4	7000000673			(4,263,914)	(4,404,919)	
Residual Account	407.3	7000001030		891,283			
Total Amortization			5,571,853	18,129,985	11,958,478	32,108,810	34,099,962
Excl. ISFSI Tax Credits			23,668,122	18,240,275	11,958,478	32,108,810	34,099,962

PGE Exhibit 305
Income Tax Summary
Reasons For Change (UE 262 and UE 266 2014 Test Year vs. 2015 Test Year)
(000s)

Income Tax Expense	UE 262 2014 Test Year	2015 Test Year
Book Revenues	1,747,665	1,766,021
Book Expenses (including Depreciation)	1,449,161	1,464,031
Interest Deduction	84,617	84,987
Book Taxable Income	213,888	217,003
Permanent Sch. M	(17,560)	(20,679)
Temporary Sch. M	21,363	(26,469)
Tax Taxable Income	210,085	264,151
Current State Taxes	15,701	20,112
State Tax Credits	(3,017)	(3,009)
Net State Income Tax	12,683	17,103
Federal Taxable Income	197,402	247,048
Current Federal Taxes	69,091	86,467
Federal Tax Credits	(25,294)	(28,929)
ITC Amortization	-	-
Deferred Taxes	8,515	(10,574)
Total Income Tax	64,994	64,067
Effective Tax Rate	30.39%	29.52%
Change in Taxes		(928)
Analysis of Tax Change:		
Effective Tax Rate Change		-0.86%
Book Taxable Income (UE 262)		213,888
Increase in Taxes Due to Higher Effective Rate		(1,848)
Change in Book Taxable Income (2015 vs UE 262 and UE 266)		3,115
2015 Effective Tax Rate		29.52%
Increase in Taxes Due to Higher Book Taxable Income		920
Sum of Tax Impacts		(928)

PGE Exhibit 306
Taxes Other Than Income
2011 - 2015 Test Year

Item	FERC Account	AWO	2011 Actual	2012 Actual	2013 Forecast	2014 Forecast	2015 Forecast
Payroll Taxes	408.1	Note 1	12,572,279	12,708,261	13,182,613	13,135,976	14,033,112
Property Taxes - Oregon	408.1	4081001	37,765,568	40,650,530	43,491,466	46,406,028	46,458,873
Property Taxes - Washington	408.1	4081002	45,644	36,072	41,616	53,172	50,006
Property Taxes - Montana	408.1	4081003	3,907,047	3,847,368	3,928,662	4,452,852	4,633,452
Franchise Fees	408.1	4081010, 4081011	40,567,687	42,081,393	41,517,105	42,233,376	43,582,665
Foreign Insurance Excise Tax	408.1	4081012	-	9,600	9,600	-	-
Misc. Tax & Lic Fees - Oregon	408.1	4081013	1,342,211	1,311,815	1,253,172	1,220,025	1,408,391
Misc. Tax & Lic Fees - Montana	408.1	4081014	360,758	401,367	419,208	368,900	426,300
Total Taxes Other Than Income			96,561,192	101,046,406	103,843,443	107,870,329	110,592,799

Note 1: Payroll Tax accounts include 4081004, 4081005, 4081006, 4081007, 4081008 and 4081009

PGE Exhibit 307
Rate Base (000s)
Based on Ending 12/31/14 Balance

		12/31/2014 Balance
	Plant in Service	7,293,364
Less:	Accumulated Depreciation/Amortization	(3,805,842)
	Accumulated Deferred Taxes	(579,549)
	Accumulated Deferred ITC	-
Net Utility Plant		2,907,972
Operating Materials and Fuel Stocks		75,103
Deferred Debits		
	Sunway III	1,581
	Colstrip Common FERC Adj	742
	Glass Insulators	2,582
	Dispatchable Standby Generation	5,617
	UE 197 Generation Maintenance Deferral	2,738
	Major Maint. Accruals (Coyote & PW)	2,743
	CET	6,400
	IT	6,947
	Energy Imbalance Market	1,500
Deferred Credits		
	Injuries & Damages	(8,705)
	Customer Deposits	(13,358)
	Customer Advances	(10)
	Pension	49,060
	Misc. Other	(38,727)
Working Capital		56,540
Rate Base		3,058,727

PGE Exhibit 308
Rate Base Comparison
UE 262 vs. 2015 Test Year
(000s)

	UE 262 Test Year	Working Cash Requirements	Coyote Maj. Maint. Accrual	Port Westward Major Maint. Accrual	Energy Imbalance Market	Accum. Def. Taxes (bonus depr., etc.)	Misc. Other	2015 Test Year
Plant in Service	7,190,614						102,750	7,293,364
Accumulated Depr/Amort	(3,729,761)						(76,081)	(3,805,842)
Accumulated Deferred Taxes/ITC	(506,554)					(72,995)		(579,549)
Net Utility Plant	2,954,299	-	-	-		(72,995)	26,669	2,907,972
Other Rate Base	43,894		231	2,512	1,500		46,077	94,215
Working Cash	56,024	516	-	-			-	56,540
Rate Base	3,054,217	516	231	2,512	1,500	(72,995)	72,746	3,058,727

PGE Exhibit 309
Base Unbundled Results of Operations Summary
2015 Results at Reasonable Return
Dollars in $000s

	Production	Transmission	Distribution	Ancillary	Metering	Billing	Consumer	Total
Operating Revenues								
Sales to Consumers (Rev. Req.)	1,035,643	35,360	551,315	4,900	2,515	57,454	55,313	1,742,500
Sales for Resale	-	-	-	-	-	-	-	-
Other Operating Revenues	4,153	9,991	14,242	(4,900)	2	5	27	23,521
Total Operating Revenues	1,039,796	45,351	565,556	-	2,517	57,459	55,341	1,766,020
Operation & Maintenance								
Net Variable Power Cost	593,425	-	-	-	-	-	-	593,425
Total Fixed O&M	139,516	12,020	94,623	-	-	-	-	246,159
Other O&M	57,338	4,818	73,141	-	1,764	51,640	45,145	233,846
Total Operation & Maintenance	790,279	16,838	167,764	-	1,764	51,640	45,145	1,073,430
Depreciation & Amortization	110,198	11,126	147,974	-	2,236	4,442	4,033	280,008
Other Taxes / Franchise Fee	29,033	3,279	72,953	-	438	825	4,065	110,593
Income Taxes	1,959	4,561	56,953	-	(500)	358	735	64,067
Total Oper. Expenses & Taxes	931,470	35,803	445,645	-	3,937	57,265	53,977	1,528,097
Utility Operating Income	108,326	9,548	119,912	-	(1,420)	194	1,364	237,923
Rate of Return	7.78%	7.78%	7.78%	N/A	7.78%	7.78%	7.78%	7.78%
Return on Equity	10.00%	10.00%	10.00%	N/A	9.83%	9.83%	9.83%	9.83%
Rate Base								
Utility Plant in Service	3,434,698	287,305	3,421,370	-	67,052	33,194	49,745	7,293,364
Accumulated Depreciation	1,768,560	137,318	1,768,696	-	73,538	28,860	28,871	3,805,842
Accumulated Def. Income Taxes	389,219	33,148	126,782	-	14,852	5,030	10,518	579,549
Accumulated Def. Inv. Tax Credit	-	-	-	-	-	-	-	-
Net Utility Plant	1,276,919	116,840	1,525,892	-	(21,338)	(696)	10,356	2,907,972
Operating Materials & Fuel	64,656	1,404	9,044	-	-	-	-	75,103
Misc Deferred Debits	32,013	4,845	25,985	-	4,113	1,694	11,262	79,912
Misc. Deferred Credits	(15,418)	(1,666)	(35,830)	-	(1,175)	(626)	(6,085)	(60,800)
Working Cash	34,464	1,325	16,489	-	146	2,119	1,997	56,540
Total Rate Base	1,392,634	122,746	1,541,579	-	(18,254)	2,491	17,529	3,058,727

PGE Exhibit 310
Total Unbundled Results of Operations Summary
2015 Results at Reasonable Return
Dollars in $000s

	Production	Transmission	Distribution	Ancillary	Metering	Billing	Consumer	Total
Operating Revenues								
Sales to Consumers (Rev. Req.)	1,130,714	35,360	554,278	4,900	2,515	57,454	55,313	1,840,534
Sales for Resale	-	-	-	-	-	-	-	-
Other Operating Revenues	4,153	9,991	14,242	(4,900)	2	5	27	23,521
Total Operating Revenues	1,134,866	45,351	568,520	-	2,517	57,459	55,341	1,864,055
Operation & Maintenance								
Net Variable Power Cost	575,789	-	-	-	-	-	-	575,789
Total Fixed O&M	149,468	12,020	94,623	-	-	-	-	256,111
Other O&M	58,417	4,818	73,641	-	1,764	51,640	45,145	235,424
Total Operation & Maintenance	783,674	16,838	168,264	-	1,764	51,640	45,145	1,067,324
Depreciation & Amortization	147,457	11,126	147,974	-	2,236	4,442	4,033	317,267
Other Taxes / Franchise Fee	37,448	3,279	75,405	-	438	825	4,065	121,460
Income Taxes	(4,341)	4,561	56,957	-	(500)	358	735	57,770
Total Oper. Expenses & Taxes	964,238	35,803	448,600	-	3,937	57,265	53,977	1,563,821
Utility Operating Income	170,628	9,548	119,920	-	(1,420)	194	1,364	300,234
Rate of Return	7.78%	7.78%	7.78%	N/A	7.78%	7.78%	7.78%	7.78%
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	4,255,152	287,305	3,421,370	-	67,052	33,194	49,745	8,113,818
Accumulated Depreciation	1,787,070	137,318	1,768,696	-	73,538	28,860	28,871	3,824,352
Accumulated Def. Income Taxes	435,645	33,148	126,782	-	14,852	5,030	10,518	625,975
Accumulated Def. Inv. Tax Credit	(44,222)	-	-	-	-	-	-	(44,222)
Net Utility Plant	2,076,660	116,840	1,525,892	-	(21,338)	(696)	10,356	3,707,713
Operating Materials & Fuel	64,656	1,404	9,044	-	-	-	-	75,103
Misc Deferred Debits	32,013	4,845	25,985	-	4,113	1,694	11,262	79,912
Misc. Deferred Credits	(15,418)	(1,666)	(35,830)	-	(1,175)	(626)	(6,085)	(60,800)
Working Cash	35,677	1,325	16,598	-	146	2,119	1,997	57,861
Total Average Rate Base	2,193,587	122,746	1,541,689	-	(18,254)	2,491	17,529	3,859,789

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 283

Port Westward 2
Tucannon River Wind Farm

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony of

Maria Pope
Jim Lobdell

February 13, 2014

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I. Introduction

Q. Please state your names and positions with PGE?

A. My name is Maria Pope. My position at PGE is Senior Vice President of Power Supply and Operations and Resource Strategy. My qualifications appear at the end of this testimony.

My name is Jim Lobdell. I am Senior Vice President, CFO and Treasurer. My qualifications appear in PGE Exhibit 100.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to describe PGE's new generation resources, Tucannon River Wind Farm (Tucannon) and Port Westward 2 (PW2). We review the integrated resource planning (IRP) and request for proposals (RFP) processes that led to their selection. We also discuss the associated costs of the resources and PGE' construction progress to date.

Q. How do you organize your testimony?

A. Our testimony is organized into six sections:

- Section I: Introduction
- Section II: IRP and RFP Processes
- Section III: Tucannon River Wind Farm
- Section IV: Port Westward 2
- Section V: Conclusion
- Section VI: Qualifications

II. IRP and RFP Processes

A. Integrated Resource Planning Process

<u>Tucannon River Wind Farm</u>

Q. Why did PGE decide to build Tucannon?

A. PGE's 2009 Integrated Resource Planning (IRP) action plan identified the need for 122 MWa of renewable energy to physically meet the 2015 Renewable Portfolio Standard (RPS) target. PGE conducted an RFP that resulted in the selection of Tucannon as the least cost, least risk bid. PGE then completed negotiations to acquire the development rights from Puget Sound Energy (PSE) and to procure Wind Turbine Generators (WTG) from Siemens. A Balance of Plant Engineering Procurement and Construction (EPC) contract was signed with Renewable Energy Systems Americas (RES).

Q. Did any updates to the 2009 IRP change the identified need for renewable energy?

A. The updated IRP slightly reduced the target. The IRP update confirmed the need for additional renewable resources. Although load growth was lower than forecasted in the 2009 IRP, the updates continued to show a significant need for renewable resources. This requirement was adjusted from the original 122 MWa to about 101 MWa in the November 23, 2011 IRP Update.

<u>Port Westward 2</u>

Q. Why did PGE decide to build PW2?

A. There were two stages in PGE's decision to build PW2:

1. The 2009 IRP action plan identified the need for approximately 200 MW of flexible capacity to fulfill the dual purpose of meeting load during peak customer

demand events as well as providing flexible capacity to follow both load and wind fluctuations.

2. The ensuing 2012 RFP resulted in the selection of the PW2 project as the least cost, least risk bid.

Q. Has the update to the IRP changed the need for capacity?

A. No. The IRP Update confirmed the need for the additional capacity. Although recent load growth is lower than what was previously forecasted in the 2009 IRP, there is still a significant need for capacity. This need for capacity falls into two categories: peaking and flexible capacity.

Q. What is peaking capacity?

A. The IRP identified a peaking capacity need of approximately 200 MW bi-seasonal (winter and summer) and an additional 150 MW for the winter season only. The peaking capacity need is determined by taking the forecasted 1-hour peak energy load for the year less the total capacity within PGE's portfolio of assets.

Q. What is flexible capacity?

A. Flexible capacity is designed to respond on short notice and has the ability to ramp up and down quickly. A resource that can provide flexible capacity can also provide peaking capacity. In addition, during normal operation hours that are outside of the peak load events, flexible capacity will also be able to provide ancillary services. These ancillary services include regulation, load and wind following (intra-hour ramping capabilities), and spinning/non-spinning reserves.

Q. How is the need for additional flexible capacity determined?

A. The need for flexible capacity depends on both system requirements for flexible capacity and the amount of existing flexible capacity on PGE's system. Over time, PGE has been experiencing an increase in requirements for flexible capacity coinciding with a decrease in access to flexible capacity.

B. Request for Proposals Process

Q. When the IRP process was finalized, what steps did PGE take to acquire the needed resources?

A. The first step PGE took was to develop and publish an RFP to select an independent evaluator (IE). Once that was complete, PGE took the following steps towards resource acquisition:

- PGE developed and published two RFPs: one for renewable resources (UM 1613) and a separate combined capacity and energy RFP (UM 1535).
- PGE received project bids for each RFP and then scored the bids.
- PGE published an initial short list and selected a final short list.
- PGE began contract negotiations with the top-rated bid, unless PGE's benchmark bid was the top-rated bid.

Q. How was the IE selected to oversee the resource RFPs?

A. After evaluating the responses to the RFP to select an IE (UM 1524), PGE made its recommendation to OPUC Staff and Stakeholders. Based on Staff's recommendation, the Commission appointed ACCION Group to serve as the IE for PGE's combined Capacity and Energy RFP as well as for the Renewable RFP.

Q. Who was the IE ultimately answerable to?

A. The IE reported directly to the Public Utility Commission of Oregon and its work was directed by the OPUC Staff. Its primary task was to ensure that the RFPs were conducted fairly and in compliance with all rules and regulations. The IE reviewed draft RFP documents and submitted an assessment of the RFPs to the Commission before they were issued. The IE independently scored all short-listed bids and submitted closing reports to the Commission after PGE identified the final short lists.

Q. How was project scoring weighted between price and non-price criteria?

A. For both RFPs, the scoring criteria were divided into two categories: price and non-price. Out of 1,000 possible points, 600 points were allocated to price and the remaining 400 points were allocated to non-price criteria.

Q. How did PGE determine the price scores?

A. PGE prepared financial models for all submitted bids. These models calculated a lifecycle economic value for each bid. The final price score was based on the ratio of the bid's total real levelized cost of energy (RLCOE expressed in $/MWh) to the RLCOE of the market alternative over the same term.

Q. Why did PGE negotiate with only the top bidder for the renewable resource?

A. The purpose of the RFP process is to acquire resources that provide PGE's customers with the best combination of cost and risk. To this end, was it important that the bidding process encouraged bidders to submit bid prices that represented the best and most accurate costs of the resource. By restricting negotiations to the top bidder, and retaining the option to open parallel negotiations concerning an alternative bid, or to terminate discussions concerning the top bidder, the process encouraged bidders to submit their best offers in their bid submittals. PGE was then positioned to compare resources and select the short list on the basis of each project's true costs. As articulated in the IE's report, this "negotiation strategy proved to be successful and parallel negotiations with other bidders was unnecessary."

Q. How did PGE maintain leverage during exclusive negotiations with the top scored bid?

A. The RFP required that bids contain all major commercial and other material terms, and be held firm for a stated period of time. This was designed to limit the items to be negotiated. In addition, PGE made clear in the RFP documents that it would shortlist more bids than required to satisfy the need identified in the IRP. Bidders were also informed that in the event negotiations with the top bidder did not proceed expeditiously, or material terms of the bid were not maintained, PGE would have the ability to open negotiations with the next best bid. This practice enhanced the fairness of the process for all bidders.

<u>Tucannon River Wind Farm</u>

Q. Was there public involvement in the drafting of the Renewable RFP?

A. Yes. PGE Staff conducted workshops for bidders and stakeholders. Approximately 63 bidders and stakeholders attended these workshops. In addition, the IE hosted a website with a 'Question & Answer' section where questions from bidders and stakeholders could be posted. PGE and the IE responded to 73 questions on the website. Finally, the RFP was reviewed as part of a public process in Docket UM 1613. Accordingly, stakeholders had an opportunity to provide written comments on the draft RFP before it was finalized and had an opportunity to provide oral comments at a Commission public meeting.

Q. Did PGE submit a self-build benchmark resource bid?

A. Yes.

Q. What procedures did PGE put in place to ensure objectivity in the bid evaluation process?

A. The group of employees whose primary duty was to submit the benchmark resource bid was physically and functionally separated from PGE's RFP evaluation team and interactions between the two groups were restricted to ensure impartiality in the bid evaluation process.

Q. In addition to the firewall between the PGE bid team and the RFP evaluation team, did the IE take any measures to ensure that the PGE RFP Team's assessment of the renewable bids was fair and accurate?

A. Yes. In accordance with the Commission's RFP guidelines, the benchmark was submitted and scored and reconciled with the IE before PGE opened any third-party bids. The benchmark bid was independently scored by the IE and any differences between the IE's score and PGE's score were reconciled. The score was then submitted to the OPUC Staff and locked down to ensure that the benchmark bid scores could not be modified after third-party bids had been reviewed and scored.

Q. Did the IE independently score bids on PGE's renewables RFP short list?

A. Yes. The IE independently scored all bids on the short list and worked with PGE to reconcile any discrepancies in scoring.

Q. How was the initial short list developed?

A. The initial short list was developed in accordance with RFP documents. The top three factors analyzed in selecting the initial short list were capacity, transmission costs and risks, and the ability to use production tax credits.

Q. How was the final short list determined?

A. PGE, with oversight from the IE, performed additional analyses between the initial short list and the final short list. Specifically, the additional analysis focused on transmission, credit, and the bids' (or combination of bids') impact to PGE's total system costs.

Q. Did PGE select its renewable benchmark capacity bid?

A. No. PGE selected another resource that was deemed to be least cost and least risk.

Q. What was the selected bid?

A. PGE selected the Lower Snake River Phase II (LSR II) wind farm. This bid was submitted by PSE, which owns and operates Lower Snake River Phase I. The bid was submitted with RES as the EPC partner and Siemens as the turbine manufacturer. This bid presented customers and PGE with the lowest cost and lowest risk project. PGE changed the name of LSR II to Tucannon River Wind Farm for an identity unique to PGE.

<u>Port Westward 2</u>

Q. Was there public involvement in the drafting of the combined Capacity and Energy RFP?

A. Yes. Similar to the process for the Renewable RFP, PGE submitted a draft RFP to the Independent Evaluator (IE) on June 28, 2012. Another draft that incorporated the IE's suggestions was provided to stakeholders and other interested parties on July 6, 2012. In the period following the distribution of the drafts, PGE conducted four workshops for bidders and two workshops for stakeholders. The IE was available at the workshops to field bidders' questions and hosted a website where 191 questions were responded to by PGE and the IE.

Q. Did PGE submit a self-build benchmark capacity resource bid?

A. Yes. PGE submitted bids for two alternative capacity resources; one alternative was backed by two simple cycle combustion turbines and the other was backed by multiple reciprocating engines.

Q. How did the IE ensure that the PGE RFP Team's assessment of the combined Capacity and Energy RFP bids was fair and accurate?

A. As with the renewable bids, PGE followed the Commission's RFP guidelines that require the benchmark to be submitted and scored before the opening of third-party bidding. The benchmark bids were independently scored by the IE and differences between the IE's scores and PGE's scores were reconciled. The scores were then submitted to the OPUC Staff and locked down to ensure that the benchmark bid scores could not be modified after other bids had been reviewed and scored.

Q. How was the initial short list developed?

A. The initial short list was developed based on the individual bid scores. After the price and non-price scores were assessed, the RFP Team and the IE compared scores and reconciled any scoring discrepancies. Eleven bids made the initial short list.

Q. How was the final short list determined?

A. In accordance with relevant Commission orders, after the initial short list was developed, bids on the initial short list were subject to additional analysis. Credit, transmission and gas transport were further analyzed consistent with the Competitive Bidding Guidelines. PGE's benchmark resource emerged as the least cost and least risk resource for customers and PGE.

Q. Did the IE independently score short-listed bids to PGE's capacity and energy RFP?

A. Yes. The IE independently scored all bids on the short list and worked with PGE to reconcile any discrepancies in scoring.

Q. Did PGE select its benchmark capacity bid?

A. Yes. The PW2 project, based on reciprocating engines, offered PGE's customers the best combination of cost and risk to meet PGE's capacity resource need.

III. Tucannon River Wind Farm

Q. Please describe the Tucannon project.

A. Tucannon is located in Columbia County, south of the Tucannon River in eastern Washington. The project has a nameplate capacity of 266.8 MW[1], which consists of 116 Siemens SWT-2.3-108 turbines installed on 80 meter (approximately 262.5 feet) tubular steel towers and the associated turbine foundations.

PGE will be the owner/operator of Tucannon. The contracting structure includes an Asset Purchase Agreement with PSE, EPC with RES, and a Turbine Supply Agreement and Service and Maintenance Agreement with Siemens Energy (SEI or Siemens).

A. Scope

Q. What do you discuss in this portion of your testimony?

A. We discuss Tucannon plant technology, project costs, performance guarantees, and construction progress to date.

<u>Turbines Supply and Technology</u>

Q. Why were Siemens' turbines chosen for Tucannon?

A. The proposal submitted by PSE, which was evaluated as the best performing bid, to the PGE 2012 Renewable Resource Request for Proposals (RFP) was based on Siemens' SWT-2.3-108 turbines. PGE evaluated bids from both Siemens and Vestas in negotiations for turbine supply. Siemens Energy (SEI), Inc. was chosen after a comprehensive evaluation of both Siemens and Vestas technologies, costs and risks. The selection of Siemens wind turbine generators provided the best value for the project.

Q. Is there any warranty with Siemens for the turbines?

[1] 266.8 MW, with a 36.8 percent capacity factor equates to approximately 98 MWa. This compares to PGE's need for approximately 101 MWa of renewable energy in the IRP Update.

A. Yes. There is a 2-year warranty for the turbines.

Q. What is Tucannon's capacity factor using the Siemens SW 2.3-108 turbines?

A. A forecast of the long-term energy output of the proposed wind farm using a layout of 116 Siemens SWT-2.3-108 turbines was provided with the PSE RFP bid. At the request of the IE, studies from all the submitted bids were reviewed by DNV KEMA, an independent consulting firm. DNV KEMA's study estimated the projected net capacity factor of Tucannon over the first 20 years of operation, based on a probability of exceedance of 50 percent, is approximately 36.8 percent. This included calculation of the wake and air density effects and assumptions or estimates for availability, electrical efficiency, turbine performance, environmental and curtailment losses.

<u>Balance of Plant Contractor</u>

Q. How was RES chosen as the construction contractor for Tucannon?

A. The proposal submitted by PSE, which was evaluated as the best performing bid, requires RES to be the balance of plant construction contractor. PGE negotiated and entered into an EPC Agreement with RES in June 2013.

Q. Please tell us more about RES.

A. RES is one of the top renewable energy companies in North America. The RES Group of companies has constructed nearly 100 wind projects with a total capacity of more than 8,000 MW around the world. RES has been active in North America since 1997, and has a renewable energy construction portfolio that exceeds 7,000 MW and includes over 65 projects, as well as 534 miles of overhead and transmission lines. In addition, RES currently operates more than 600 MW of renewable energy.

Q. What warranties are in place to ensure that the construction of Tucannon is completed on time and functions as required?

A. There are warranty provisions in the EPC agreement that ensure work will be free from defect and the facility performs its intended function. RES and SEI are required to complete project milestones by certain dates and are subject to liquidated damages for failure to meet guaranteed dates. The RES warranty period commences on the Substantial Completion Date and continues for two years. In addition, RES is required to maintain insurance coverage including commercial general liability, automobile and professional liability insurance.

<u>Service and Maintenance Agreement</u>

Q. Does PGE have a long-term service and maintenance agreement with Siemens?

A. Yes. For a period of five years, Siemens will service and maintain equipment including maintenance, inspections and anything required by the Operations Manual. SEI will hire and direct all employees providing the services. SEI will collect data and remotely monitor the turbines 24-hours per day and respond to unscheduled outages.

<u>Transmission and Interconnection</u>

Q. Is Tucannon within BPA's system control area?

A. Yes.

Q. Has PGE entered into a Large Generator Interconnection Agreement (LGIA) with BPA?

A. Yes. PGE has entered into an LGIA with BPA for Tucannon. It covers connection of a 230 kV generation lead from the Project Substation to Central Ferry Substation.

Q. Please describe the transmission arrangements for Tucannon.

A. PGE has acquired 267 MW of transmission service on BPA's transmission system through assignment of several Precedent Transmission Service Agreements (PTSAs) from PSE. These PTSAs give PGE the rights to 267 MWs of transmission service once the project is complete. The nature of the service will be contingent on the construction and completion of BPA's Central Ferry Lower Monumental 500kV transmission line. If the line is not completed by December 2014, PGE will receive Conditional Firm Service from BPA until such time that the line is completed. As part of the project acquisition, PSE has agreed to make PGE whole if PGE is curtailed during this conditional firm transmission bridge phase, which expires in December 2017. The total cost for the PTSAs was $20.5 million.

B. Tucannon Project Costs

Q. What costs are associated with Tucannon?

A. Costs for Tucannon consist of the following major categories:

- Capital expenditures total approximately $500 million; we expect the plant to be in service in the first half of 2015. This excludes allowance for funds used during construction.
- Production O&M expense is forecasted to be approximately $8.5 million in the 2015 test year before consideration of the dispatch benefits in NVPC. This consists of approximately $0.8 million in labor costs related to 5 FTEs plus additional contract labor, plus $7.7 million in non-labor costs.
- Insurance and A&G are forecasted to be approximately $0.4 million.
- Net Variable Power Costs (NVPC) will decline when Tucannon is added to PGE's system. The details of this cost impact are discussed in PGE Exhibit 500.

- Depreciation expense is forecasted to be approximately $23.7 million in the 2015 test year based on a 30 year depreciable life for the plant.
- Property Taxes are forecasted to be approximately $6.9 million due to Tucannon.

Additional detail related to these costs can be found in PGE Exhibit 300.

Q. What is the net revenue requirement impact for Tucannon?

A. The net revenue requirement is approximately $46.7 million. Details for this calculation as well as rate base are provided in PGE Exhibit 300.

C. Project Execution

Q. Is the project currently within budget and on schedule?

A. Yes. The project is currently within budget and on schedule.

Q. How do the capital costs used in the revenue requirement calculation compare with the capital cost estimate provided with the RFP bid?

A. As part of the RFP evaluation of the PSE bid, PSE provided a cost estimate. During negotiations between PSE and PGE an overall cost estimate of $500 million was established. By participating in Washington’s Renewables Sales Tax Exemption, which was subsequently passed by the Washington Legislature post contract execution between PGE and PSE, PGE will realize sales tax savings of approximately $23 million compared to the tax amount in the bid. Therefore, our current best estimate of actual capital costs is approximately $23 million lower than the estimate provided in the bid.

D. Project Timeline and Milestones

Q. Has RES provided a guaranteed substantial completion date for Tucannon?

A. Yes. The guaranteed substantial completion date for RES’ Scope of Work is December 19, 2014.

Q. What is the expected date of operation for Tucannon?

A. PGE expects Tucannon to come on line in the first half of 2015.

Q. How far along is construction at this time?

A. As of January 2014, overall project completion is approximately 20 percent. Approximately 10 miles of roads have been constructed and 25 foundations have been poured and backfilled. Turbine manufacturing is approximately 37 percent complete. A total of 250 blades, 42 hubs, 42 nacelles and 6 towers have been assembled. Deliveries to the site will begin in June 2014.

Q. What is the construction schedule for Tucannon?

A. Table 1 provides the construction schedule:

Table 1
Tucannon Milestones

Milestone	Actual/Scheduled Completion
Roads	Sept 2013 - Jun 2014
Foundations	Oct 2013 – Jul 2014
Substation	Mar 2014 – Aug 2014
O&M Building	Mar 2014 – Aug 2014
Transmission Line	Mar 2014 – Aug 2014
Turbine Delivery	Jun 2014 – Sept 2014
Turbine Erection	Jun 2014 – Oct 2014
Turbine Commissioning	Aug 2014 – Mar 2015
Interconnection with BPA	December 2014
Initial Operation	First half of 2015
Substantial Completion	First half of 2015

IV. Port Westward 2

Q. Please describe the PW2 generating facility.

A. PW2 consists of twelve natural gas reciprocating engines with a combined capacity of approximately 220 MW[2] available at a heat rate of approximately 8,312 Btu/kWh when new.[3] The plant is designed to provide flexible capacity that can be deployed on short notice.

Q. What PGE system requirements does PW2 supply?

A. PW2 supplies generating capacity that provides planning reserves and ancillary services. Planning reserves are capacity resources used to meet annual and seasonal peak loads. Ancillary services require flexible capacity and are typically categorized as:

- Operating reserves (both spinning and non-spinning) - PGE is required to maintain capacity reserves to be able to react to loss of generation.
- Balancing reserves - PGE must maintain reserves to adjust generation when actual generation differs from forecast generation.
- Load and wind following - Within the hour, resources must be available to track movements in load and wind.
- Regulation - Over short time frames, system generation must be continuously adjusted to balance generation to load.

A. Scope

Q. What do you discuss in this portion of your testimony?

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[2] Gas-fired capacity figures are for January. Output is somewhat lower in warmer months, as maximum capacity varies inversely with temperature.

[3] Degradation will increase Port Westward 2's heat rate by approximately 0.6% soon after the plant goes on-line. The same fuel input will result in less output. This is a normal occurrence with gas-fired plants and was incorporated in PGE's bid.

A. We discuss the need for PW2 flexible capacity, plant technology, contractors partnering with PGE, performance guarantees, and construction progress to date.

Need for Flexible Capacity Resources

Q. Why does PGE require flexible capacity resources?

A. As more fully addressed in the 2009 IRP, the Northwest has recently experienced modest load growth. However, the growth in renewable energy supplies, mostly in the form of wind energy, has been significant. When wind energy is added to a utility system, its natural variability and uncertainty are compounded by the variability and uncertainty of loads. As a result, there is an increase in the need for system flexibility required to maintain utility system balance and reliability.

Historically, PGE has relied on hydroelectric resources, both owned and contractual, to track movements in load and to provide operating reserves. Over time, PGE's share of Mid-Columbia hydro resources continues to decline for various reasons. In addition, the flexibility of all regional hydro resources has declined as environmental regulations and competing uses for the water place tighter constraints on system operation.

Technology

Q. Please describe the technology at PW2.

A. PW2 will be a state-of-the-art, highly efficient, and environmentally responsible power plant consisting of multiple natural gas fired reciprocating engine generators with a nominal generating capacity of 220 MW. The PW2 plant will provide flexibility needed to maintain PGE's system balance and reliability.

This technology has low air emissions and is very efficient and highly flexible. The natural gas-fired engines are capable of reaching full load from standby condition within 10 minutes. PW2 will be designed to provide peaking capacity and intermediate energy load service as well as ancillary services needed for load-following and wind integration. The ancillary services will include spinning reserve, non-spinning reserve, load-following, and reserve margin.

Operating characteristics of a gas-fired engine plant vary slightly with ambient air temperature. At the 51° F ambient design temperature and 78% relative humidity, the heat rate for PW2 will be approximately 8,312 Btu/kWh when the plant is in new and clean condition. The plant has very high part-load efficiency.

EPC Contractor and Performance Guarantees

Q. Who did PGE select as the EPC contractor?

A. PGE selected Columbia River Power Constructors (CRPC), a contractual joint venture between Black and Veatch Construction, Inc. and Harder Mechanical Contractors, Inc., as the EPC contractor. PGE partnered with CRPC to bid into the PGE Request for Proposals (RFP) for the PW2 benchmark bid. During the preliminary engineering phase of the project, we investigated other parties that might have the capabilities and experience to design and build the project.

Q. Why did PGE select CRPC as a partner?

A. CRPC provided a good combination of guaranteed price, experience, and performance guarantees. Black & Veatch is a major international engineering construction and consulting firm headquartered in Kansas City. It is employee-owned and works in a variety of fields including power generation, power delivery, gas, oil, and chemicals. Black & Veatch was PGE's EPC contractor for the first Port Westward plant and performed well on that project. Harder Mechanical is a large construction company based in Portland with excellent experience with large projects.

Q. What plant performance guarantees has CRPC provided?

A. The plant must meet a number of performance guarantees including:

- output and heat rate at base load,
- output at minimum load,
- engine lubrication oil consumption,
- ammonia consumption,
- stack air emissions,
- startup times,
- ramp rates,
- load following ability,
- starting reliability,
- availability, and
- noise levels.

For some guarantees (e.g. stack air emissions, load following ability, etc.) CRPC must physically remedy any problems that cause the plant to not achieve the guarantees, regardless of cost to CRPC. With other guarantees (e.g. output and heat rate at base load), for deviations within five percent of the guarantees, CRPC can either provide physical remedies or pay damages.

Q. Has CRPC provided a guaranteed completion date for the PW2 project?

A. Yes. The planned completion date is the first quarter 2015, and the guaranteed completion date is January 31, 2015. CRPC must pay liquidated damages if the work is not completed by the guaranteed date.

Equipment Manufacturer and Long Term Service Agreement

Q. Please describe the equipment manufacturer?

A. Wärtsilä North America (WNA) manufactures power plants for marine and energy applications. The company specializes in plants powered by natural gas and liquid fuels. In 2012, WNA had net sales worldwide of approximately EUR 4.7 billion with approximately 18,900 employees. The company operates in 70 countries.

Q. Has PGE signed a long-term service agreement for PW2?

A. Yes. PGE and WNA North America signed a long-term service agreement (LTSA) which provides long-term major maintenance services to ensure ongoing plant reliability. The LTSA provides assurance and predictability of maintenance.

Q. What are the provisions of the LTSA?

A. The LTSA is a 36,000 running hour (per engine) or 10-year contract. It has a fee structure based on operating hours, under which PGE will make payments and, in return, WNA will provide periodic operating hour-based and condition-based maintenance inspections. These inspections will include component repair and replacement.

The LTSA carries a warranty that addresses all warranty-related work for parts and services. It includes an on-site inventory, for which PGE pays a nominal storage fee, for all LTSA-covered parts. PGE is then billed for parts as they are taken out of inventory for use in the generation units. PGE will also receive 24-hour online monitoring of the plant through WNA's on-line monitoring system, primarily staffed from their Ft. Lauderdale service center. In addition, the LTSA covers unplanned work that PGE, at its discretion, may ask WNA to perform for agreed upon labor rates specified in the LTSA. The agreement has known escalation and exchange rate clauses based on published exchange rates and labor and material indices, and an early termination clause which allows PGE to discontinue the arrangement at any time with 180-day notification.

Q. PGE has proposed major maintenance accruals in the past for other thermal plants. Is PGE also proposing a major maintenance accrual for PW2?

A. Yes. As discussed in PGE Exhibit 300, PGE is proposing a major maintenance accrual based on the projection of LTSA expenses and other major maintenance or inspections not covered by the LTSA. We propose a levelized amortization amount of approximately $1 million that collects those projected expenses over a period of five years.

Q. Is the proposed major maintenance accrual similar to what PGE currently uses for Coyote Springs and Port Westward 1 (PW1)?

A. Yes. PGE has used similar mechanisms for the expenses at Coyote Springs since the UE 93 proceeding. In UE 262, PGE proposed, and was granted, similar treatment for PW1.

Q. Why is a PW2 major maintenance accrual necessary?

A. Under the LTSA, PGE will make payments based on each unit's operating hours, lump sum payments for unit major inspections performed at intervals determined by the manufacturer, and a fee for the on-site inventory, all of which are specified in the LTSA. As previously stated, PW2 is a flexible capacity resource consisting of 12 individual units. Because PW2 is a flexible capacity resource, the energy output of the plant is not the most accurate measure of plant operation, as compared to a base load resource. At times, the plant may have low energy output, but will be providing flexible capacity required for reliability and reserve requirements. The variable nature of each unit's operation and the timing of required maintenance and inspections will cause significant swings in the LTSA and maintenance costs. A major maintenance accrual will help smooth the lumpy nature of these costs and result in better matching of cost with revenue. This will also reduce the frequency of rate changes by eliminating the need for an annual true-up and prevent excessive over- or under-collection for LTSA and maintenance expenses.

<u>Transmission and Gas Supply</u>

Q. Does the Port Westward site have any advantages for transmission and gas supply?

A. Yes. The site, located adjacent to the Columbia River in Columbia County, has excellent access to the Kelso-Beaver Pipeline and NW Pipeline for fuel supply. For transmission, PGE can rely on two 19-mile PGE operated 230kV lines from Port Westward to PGE's Trojan Substation. This line avoids the fixed transmission charges and imputed line losses associated with BPA transmission. Re-conductoring of approximately 9 miles of one of the two transmission lines between the Port Westward Substation and the Trojan Substation is included in the PW2 project to improve reliability for that segment of the transmission system.

Q. Will PW2 require additional gas storage?

A. Yes. Availability of gas from storage is integral to the plant's ability to provide flexible capacity. PGE has entered into a long-term "no-notice" gas storage contract for 2.54 billion cubic feet (Bcf) with Northwest Natural (NWN) from its proposed Mist Expansion facility. For 2015, PGE will obtain 360,000 dekatherms for "gap" service from NWN, which is in addition to the current 1.26 Bcf Mist contract with NWN. Gas storage costs are included in PGE's net variable power costs and are discussed in more detail in PGE Exhibit 500.

B. Port Westward 2 Project Costs

Q. What are the costs associated with PW2?

A. Costs for PW2 consist of the following major categories:

- Capital expenditures for PW2 total approximately $300 million. This excludes allowance for funds used during construction. We expect the plant to be in service in the first quarter 2015.
- Production O&M expense is forecasted to be approximately $1.5 million in the 2015 test year before consideration of the dispatch benefits in NVPC. This consists of approximately $0.3 million in labor costs plus $1.2 million in non-labor costs. Non-labor costs include approximately $1.0 million for the major maintenance accrual annual expenses. We describe the LTSA in more detail in Section IV A.
- Insurance and A&G costs are forecasted to be approximately $0.3 million.
- Net Variable Power Costs (NVPC) will decline when PW2 is added to PGE's system. The details of this cost impact are discussed in PGE Exhibit 500.
- Depreciation expense is forecasted to be approximately $13.6 million in the 2015 test year based on a 45 year depreciable life for the plant.
- Property Taxes are forecasted to be approximately $1.4 million due to PW2.

Additional detail related to these costs can be found in PGE Exhibit 300.

Q. Are there chemical costs associated with PW2?

A. Yes. The chemicals required for PW2 operation include ammonia and reciprocating engine lubricating oil. These chemical costs are not included in plant O&M, but are instead included in NVPC because their rates of use vary directly with plant output. The costs and use of these chemicals are discussed in PGE Exhibit 500.

Q. What is the net revenue requirement impact of PW2?

A. The net revenue requirement for PW2 is approximately $51.4 million. Details for this calculation are also provided in PGE Exhibit 300.

C. Project Execution

Q. Is the project within budget and on schedule?

A. Yes. The project is currently within budget and on schedule.

Q. How do the capital costs used in the revenue requirement calculation compare with the capital cost estimate provided with PGE's RFP bid?

A. As part of its bid in response to the RFP, PGE provided an overall cost estimate of approximately $300 million. Our current best estimate of actual capital costs (excluding AFUDC) is approximately $1 million lower than the estimate we provided in the bid.

D. Project Timeline and Milestones

Q. Has CRPC provided a guaranteed completion date for the PW2?

A. Yes. As we have already noted, the guaranteed completion date is January 31, 2015. CRPC must pay liquidated damages if the work is not completed by the guaranteed date.

Q. How far along is construction at this time?

A. Construction of the plant is proceeding on schedule. We have completed erection of the main building, including the two engine halls (east and west), mechanical room, electrical room, and warehouse/maintenance shop. Erection of structural steel for the exhaust systems has commenced for the east engine hall. Eleven engines and generators have been off-loaded to the site and are in the process of being set in the engine halls. One engine will be delayed due to a delivery accident. Work is ongoing for the cooling tower, service water tank, lubrication oil tank farm, and ammonia tanks.

Q. Will the delay in the delivery of the twelfth engine impact the plant in service date?

A. At this time we do not expect a delay in the in-service date.

Q. Will the delivery accident impact the cost of PW2?

A. No. PGE had not yet taken ownership of the engine and thus, costs will be covered by third-parties.

Q. What are the construction and testing milestones associated with PW2?

A. Table 2 below lists construction and testing milestones, both completed and estimated.

Table 2
Port Westward 2 Milestones

Milestone	Actual/Scheduled Completion
Start of Construction	May 13, 2013
Eleven Engines & Generators set on Foundations	February 27, 2014
One Engine & Generator set on Foundation	May 2014
First Engine Run	July 18, 2014
Switchyard Ready for Back Feed	March 20, 2014
Back Feed	April 15, 2014
Begin Commissioning of East Engine Hall	August 20, 2014
Begin Commissioning of West Engine Hall	August 27, 2014
Commercial Operation	First quarter 2015

V. Conclusion

Q. When is PGE requesting Tucannon and PW2 be in customer prices?

A. We request that prices for Tucannon and PW2 become effective once the projects are placed in service. PGE will update our cost estimates before that time.

V. Qualifications

Q. Ms. Pope, please describe your qualifications.

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 am currently Senior Vice President of Power Operations and Supply and Resource Strategy, since March 2013. Prior to that, I was Senior Vice President, Chief Financial Officer and Treasurer of PGE since 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. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 283

Net Variable Power Cost

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Michael Niman
Terry Peschka
Patrick G. Hager

February 13, 2014

Table of Contents

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.

My name is Patrick G. Hager. I am the Manager of Regulatory Affairs at PGE.

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 2015 Net Variable Power Costs (NVPC). We discuss several of the updates to parameters (e.g., plant heat rates, forced outage rates) from PGE's NVPC forecast for 2014, as well as modeling changes. We compare our initial 2015 forecast with PGE's final 2014 NVPC forecast and explain why the per-unit expected NVPC have decreased by approximately $2.11 per MWh. We also present and explain PGE's proposal to establish a practice of "carving out" renewable resources from the Power Cost Adjustment Mechanism (PCAM) and passing the incremental benefits and costs of those resources through the Renewable Resources Automatic Adjustment Clause tariff ("RAC", Schedule 122).

Q. What is PGE's initial net variable power cost forecast?

A. Our initial 2015 NVPC forecast is $580.2 million, based on contracts and forward curves as of December 5, 2013. This initial 2015 NVPC forecast represents a reduction of approximately $41.5 million relative to our final 2014 NVPC forecast filed in the 2014 NVPC proceeding (Docket No. UE 266).

Q. Will PGE make a separate 2015 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 2015 forecast to which we compare the 2015 actual NVPC pursuant to the provisions of Schedule 126, which implements the 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 501 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., February 28, 2014). As with PGE's NVPC filings in the 2014 NVPC proceeding, 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 filings:

- 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 13 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 estimate to align with the April 1 filing; and loads;

- October – 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: Docket No. UE 266 Stipulation;
- Section V: Comparison with 2014 NVPC Forecast;
- Section VI: Renewable Portfolio Standard (RPS) Carve Out; and,
- Section VII: Qualifications.

II. MONET Model

Q. How did PGE forecast its NVPC for 2015?

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, emissions control chemicals, 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 our 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. As in the 2014 NVPC proceeding, we include certain variable chemical costs. 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. Based on prior Commission decisions, certain fixed costs, such as excise taxes and transportation charges, are included with fuel costs in a balance sheet account for inventory (FERC 151); this inventory is then expensed to NVPC as fuel is consumed. 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 2015 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 does PGE use in this initial filing?

A. We use the 2015 retail load forecast described in PGE Exhibit 200. That forecast is approximately 18,809,330 MWh of cost-of-service energy, or approximately 2,147 MWa, a decrease of 6 MWa from the 2014 test year forecast in PGE's most recent NVPC proceeding in Docket No. UE 266.

Q. What updates and model changes does PGE 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 2013 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 outage rates based on 2010 through 2013 data by April 1, 2014, consistent with information that would be used in an initial AUT filing for 2015. By that date, we will have processed the 2013 data needed to complete the outage rate calculations. For this filing, we use the same forced outage rates, based on 2009 through 2012 data, from Docket No. UE 266. 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. The inclusion of PGE's new resources;
2. Updates to the Boardman plant;

3. Transmission related updates;
4. Updates to Colstrip Unit 3 and Unit 4;
5. Wind related updates;
6. New WECC operating reserve standard (WECC BAL002);
7. Update the estimated oil forward price basis differential; and,
8. The latest Pacific Northwest Coordination Agreement (PNCA) Headwater Benefits study is now included in our hydro data.

Q. What is the net effect on PGE's initial 2015 NVPC forecast of these updates and modeling changes?

A. The net effect of these updates and modeling changes is a $16.8 million decrease in PGE's initial 2015 NVPC forecast. Excluding PGE's new resources, Port Westward 2 and Tucannon River Wind Farm, the updates and modeling changes described below result in a $3.6 million decrease in PGE's initial 2015 NVPC forecast.

Q. Does PGE propose any other updates and model changes in this filing?

A. Yes. There are certain updates and modeling changes that are included in the 2015 NVPC base model. A list of these updates can be found in Volume 9 of the MFRs. We do not include these updates in the list above because they primarily consist of minor corrections and modeling clean-ups.

We discuss any forthcoming updates in more detail below.

A. New Resources

Q. Has PGE added any new resources from the 2009 IRP Final Action Plan to MONET for the 2015 test year?

A. Yes, we have added two resources, Port Westward 2 (PW2) and Tucannon River Wind Farm (Tucannon), which we discuss individually below.

1. Port Westward 2

Q. Please briefly describe PW2.

A. PW2 is a flexible capacity resource with a nameplate capacity of approximately 220 MW. The plant is located directly adjacent to PGE's existing Port Westward 1 thermal plant and consists of 12 reciprocating engines, each with a nameplate capacity of approximately 18 MW. PGE Exhibit 400 discusses PW2 in more detail.

Q. How did you model PW2 in MONET?

A. In MONET, PW2 is dispatched when economic to do so as well as when ancillary services are required. For economic energy dispatch, PW2 is modeled using the hourly dispatch logic in MONET. The hourly dispatch logic for PW2 relies on an annual heat rate, monthly capacities, variable O&M, chemical costs, forward price curves, and other parameters to dispatch the plant when the cost of generating is less than the market price for electricity in a given hour. For economic energy dispatch, each hour the entire plant is either dispatched to full capacity or offline.

Q. Please discuss how PW2 is modeled for providing ancillary services.

A. PW2 is also modeled with the ability to provide ancillary services as part of the thermal ancillary service module introduced in the Dynamic Capacity Enhancement in Docket No. UE 266. After the initial economic energy dispatch, MONET then re-dispatches the plant from its economic energy dispatch as needed to meet ancillary service requirements. MONET uses input parameters specific to the plant's ability to provide ancillary services, and the logic allows the plant to operate an incremental number of units and at partial loading as needed to meet ancillary service needs. A detailed description of both of these modeling methodologies can be found in the MFRs.

Q. What costs associated with PW2 are modeled in MONET?

A. Similar to the other gas-fired plants, such as Port Westward 1, MONET models the costs of natural gas fueling and emissions control chemicals. For PW2, MONET also models reciprocating engine lubrication oil consumption.

Q. Please discuss emissions control chemicals at PW2.

A. PW2 uses ammonia for nitrogen oxide control, similar to the Port Westward 1 and Coyote Springs plants. The use of ammonia at PW2 is essentially proportional to the generation of the plant. Consistent with the treatment in Docket No. UE 266, we include the cost of these chemicals in NVPC.

Q. Please discuss reciprocating engine lubrication oil at PW2.

A. The reciprocating engines at PW2 require reciprocating engine lubrication oil (engine lube oil). The engine lube oil is used to keep the cylinders and pistons lubricated, and with each stroke some of the oil slips past the seals and is burned in the engine. Thus, engine lube oil is consumed as the reciprocating engines run and is a variable cost measured in dollars per MWh.

Q. Does PGE include the cost of engine lube oil in the 2015 NVPC initial forecast?

A. Yes. There is a direct relationship between the plant generation forecast and the expected costs associated with engine lube oil consumption. The consumption of engine lube oil is analogous to the consumption of emissions control chemicals, which are included in NVPC.

Q. Are the costs of emissions control chemicals or engine lube oil included in any other portion of PGE's filing in this docket?

A. No. The costs of the emissions control chemicals and the engine lube oil have been removed from the O&M costs presented in PGE Exhibit 300 and PGE Exhibit 400.

Q. Please discuss fueling at PW2.

A. As discussed in PGE Exhibit 400, PGE will rely on an interim agreement for "gap" service from Northwest Natural Gas (Northwest Natural) beginning in April 2015. The gap service will provide PGE with additional storage capacity at Northwest Natural's Mist facility, which combined with PGE's current gas transportation and storage rights will be managed to fuel the addition of PW2. Currently, the fuel used by Port Westward 1 and Beaver is often in excess of PGE's firm pipeline transportation rights, resulting in PGE drawing down Mist storage. PW2 will result in further and more frequent drawdowns of Mist because the plant will rely on storage for fuel to provide flexible capacity. During heavy demand periods when Mist Storage is drawn down, PGE will need to resupply gas storage and may need to purchase delivered gas to do so due to the limits of our pipeline rights. PGE will be charged a premium inclusive of pipeline volumetric and fuel charges for the delivered gas procured. The premiums for delivered gas used in MONET are indicative prices PGE received from counterparties for delivered gas in 2014. A detailed explanation of the modeling of these fueling costs in MONET is provided in the MFRs.

Q. What are some of the benefits to NVPC that PW2 will provide?

A. PW2 will provide efficient flexible capacity that is used to provide planning reserves (e.g., for plant forced outages) and ancillary services. PGE Exhibit 400 discusses the flexible capacity benefits of PW2 in more detail. PW2 will also provide benefits to NVPC by reducing the wind day-ahead forecast error cost. We discuss the wind day-ahead forecast error cost in more detail later in this section. Due to the plant location, PGE has access to on-system transmission and is able to avoid the charges and imputed line losses associated with BPA transmission that would otherwise be incurred. PGE will still incur line losses associated with our own transmission. PW2 will also offset more costly market purchases made in MONET.

Q. How will PW2 affect PGE's initial 2015 NVPC forecast when it begins operation?

A. PW2 will decrease PGE's initial 2015 NVPC forecast by approximately $1.2 million.

Q. Does PGE plan to change how PW2 is modeled in future proceedings?

A. Yes. While we do not have specific changes planned at this point, there will likely be revisions to PW2 modeling in future proceedings beyond the 2015 test year due to changing factors such as energy imbalance markets, gas storage, increasing variable energy resources, expiring hydro contracts, and operational experience.

Q. Does PGE plan to change how PW2 is modeled in this proceeding?

A. Yes. PGE plans to update the modeling of PW2 in order to capture the integration benefits associated with PW2 during Q4 of 2015. Due to the detailed modeling and time needed for analysis and verification of the results, we were unable to quantify the benefits in time for inclusion in this initial filing. We propose to provide this update in the April 1 filing.

2. Tucannon River Wind Farm

Q. Please briefly describe Tucannon.

A. Tucannon consists of 116 Siemens 2.3 MW turbines. The facility has a nameplate capacity of approximately 267 MW and is located near Dayton, Washington. PGE Exhibit 400 discusses Tucannon in more detail.

Q. What methodology does PGE propose to use to forecast the energy output from Tucannon?

A. We propose to use the five-year moving average forecast methodology to forecast energy output from Tucannon, consistent with the methodology introduced in Docket No. UE 266. For this proceeding, all five years of the moving average calculation will be based on the initial assessment. The forecast will be updated in future AUT April filings to incorporate full years of actuals as they become available.

Q. What capacity factor is used for Tucannon in MONET?

A. During PGE's renewable resource Request for Proposals (RFP) process, the Tucannon bid was submitted with a wind study performed by RES Americas. The Independent Evaluator (IE) requested a consultant review all of the wind studies submitted during PGE's renewable resource RFP. The consultant reviewed each study and made adjustments to the energy estimates for various factors in order to provide a standard basis for evaluating each of the studies. The results were then returned to the IE and used as the basis for evaluating the bids submitted. The adjusted energy estimate for Tucannon, based on the consultant's review and adjustments, was 859 GWh per year and a capacity factor of approximately 36.8%. For this initial filing, we use the consultant's adjusted energy estimate of 859 GWh per year in MONET. Once the final siting of the Tucannon turbines is complete (i.e., all foundations are poured), PGE will commission a study to determine the expected energy output of Tucannon given any changes that may have occurred. We expect this study in time for the October update filing and will update the Tucannon energy forecast and shaping as appropriate.

Q. What costs associated with Tucannon are modeled in MONET?

A. Similar to Biglow Canyon, MONET models the costs associated with imbalance premiums, royalties, day-ahead forecast error, BPA integration, Point-to-Point transmission, and non-running station service for Tucannon. We discuss the wind day-ahead forecast error cost in more detail later in this section.

Q. What are imbalance premiums?

A. Imbalance premiums are the net costs incurred by PGE from BPA for Generation Imbalance Service at Tucannon and Biglow Canyon. According to the BPA Rate Schedules[1]:

> *Generation Imbalance Service is provided when there is a difference between scheduled and actual energy delivered from the generation resources in the BPA Control Area during a schedule period.*

Under this service, for a given schedule hour, BPA delivers to PGE the scheduled energy based on the forecast, regardless of what the plant actually generates in that hour. Our modeling focuses on imbalances within Deviation Band 2.

On an hourly basis, when the actual energy from a plant is less than the energy scheduled and within the bounds of Deviation Band 2, PGE incurs a charge from BPA for the shortfall imbalance energy priced at 110 percent of BPA's incremental cost. In the opposite case, PGE receives a credit from BPA for the surplus imbalance energy priced at 90 percent of BPA's incremental cost. Because of the difference in the shortfall and surplus rates, a net cost to PGE results over time. The estimate of imbalance costs used in MONET represents the net costs (charges less credits) incurred by PGE for imbalance within Deviation Band 2.

Q. Please explain how the imbalance premiums for Tucannon are estimated.

A. The imbalance premiums for Tucannon are estimated by calculating the product of the capacity of Tucannon, the 2011-2012 average imbalance to capacity ratio for Biglow Canyon, the hours in the period, and the monthly flat Mid-C trading curve price. This is the same methodology used for estimating Biglow Canyon imbalance premiums.

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[1] BPA 2014 Transmission, Ancillary, and Control Area Service Rate Schedules and General Rate Schedule Provisions (ACS-14).

Q. Please discuss transmission for Tucannon.

A. PGE has entered into a contract to purchase Point-to-Point transmission in order to wheel the output of Tucannon from BPA's control area to PGE's control area. For the 2015 test year, the costs associated with the Point-to-Point service from Tucannon are fully offset by transmission credits received from BPA. PGE will be charged for Scheduling Control and Dispatch (SCD) service for Tucannon, but the credits do not apply to this charge.

Q. What is non-running station service?

A. Non-running Station Service (NRSS) is the non-running internal plant load and is typically provided in one of two ways: (1) back-feed from the 230/500kV transmission system through the plant's step-up transformer or (2) direct service from a non-PGE utility or local electric Public Utility District (PUD) distribution system (i.e. not at the 230/500kV level). The cost of NRSS provided in (2) is typically accounted for in the plant's O&M budget and the cost of NRSS provided in (1) is accounted for in NVPC.

Q. Please explain how NRSS for Tucannon is estimated.

A. The estimate of NRSS for Tucannon is derived by calculating the product of the NRSS estimate for Biglow Canyon and a scaling factor. We used the ratio of Tucannon capacity to Biglow Canyon capacity to compute the scaling factor. The calculation of the NRSS estimate for Biglow Canyon is discussed in more detail later in this section.

Q. What are some of the benefits to NVPC that Tucannon will provide?

A. Tucannon will provide renewable energy that will offset market purchases made in MONET. This will decrease PGE's total NVPC. The renewable energy provided will help PGE to meet the Oregon RPS targets. As stated previously, Tucannon will also provide

PGE with a BPA wheeling credit that will largely offset the costs of Point-to-Point transmission services.

Q. How will Tucannon affect PGE's initial 2015 NVPC forecast when it begins operation?

A. We estimate Tucannon will provide net dispatch benefits of approximately $12 million. This will decrease PGE's initial 2015 NVPC forecast.

Q. Do the estimated Tucannon net dispatch benefits encompass the entire test year?

A. No. The current expected full plant on-line date for Tucannon is April 1, 2015. The net dispatch benefits associated with the portions of Tucannon that come online prior to the full plant on-line date will be included in PGE's Schedule 122 Renewable Adjustment Clause (RAC) filing.

Q. Have you annualized the dispatch benefits associated with the April-December period for rate making purposes?

A. Yes. For rate making purposes we annualize the estimated $12 million benefit by using the 2015 test year load forecast to compute a gross up factor. The resulting annual dispatch benefits are $16.4 million. This annual figure is used to derive an annual net revenue requirement of Tucannon in PGE Exhibits 300 and 400.

B. Boardman

1. PGE Ownership Share Increase

Q. How has PGE's ownership share of the Boardman plant changed compared to the 2014 test year (Docket No. UE 262/266)?

A. PGE's ownership share of the Boardman plant has increased from 65 percent to 80 percent effective December 31, 2013.[2]

[2] 145 FERC ¶ 62,213, United States of America, Federal Energy Regulatory Commission

Q. Please explain the cause of the ownership share increase.

A. In 1985, PGE agreed to sell 15 percent of Boardman to General Electric Credit Corporation (GECC) and the power to San Diego Gas & Electric under long-term contract.[3] GECC later sold its share to Bank of America Leasing LLC (BAL). Under the contract, GECC, now BAL, had the right to put the 15 percent Boardman interest back to PGE under the termination option. BAL exercised the termination option effective December 31, 2013.

Q. Has PGE made arrangements for wheeling the additional output from Boardman?

A. Yes. There is one new transmission contract included in this filing. The details of the contract are discussed in the MFRs and a copy of the contract is provided.

Q. What effect does the increase in PGE's ownership share of the Boardman plant have on PGE's initial 2015 NVPC forecast?

A. The increase in PGE's ownership share of the Boardman plant decreases PGE's initial 2015 NVPC forecast by approximately $3.4 million.

2. Biomass

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

[3] *See* Order No. 85-1236 in Docket No. UP 30

locally-accessible biomass to fuel the Boardman facility. In January 2013, PGE contracted with a vendor to 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. PGE plans to perform two test burns: (1) a co-fire test burn, using torrefied biomass and coal as fuel and (2) a 100 percent biomass test burn. The tests 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% plant output for six months of the year) as well as help PGE meet the renewable portfolio standard (RPS) of 25% of load by 2025.

Q. Is the co-fire test burn still scheduled to occur in 2014?

A. Yes. PGE plans to conduct the co-fire test burn in 2014. The costs associated with the co-fire test burn were modeled in the 2014 NVPC proceeding. PGE agreed that if the co-fire test burn did not occur in 2014, the estimated net costs will be refunded, with interest at PGE's overall cost of capital, in this 2015 NVPC proceeding. PGE continues to monitor the progress of the co-fire test burn and will update parties accordingly.

Q. Is the 100 percent biomass test burn still scheduled to occur in 2014?

A. No. As we indicated in the November 5th update of the 2014 NVPC proceeding, the 100 percent biomass test burn was rescheduled to occur in 2015 and was removed from the 2014 NVPC forecast. Step 117 of the 2014 GRC Step Change Log shows a net reduction of $2.64 million ($3.0 million in costs less the market value of the energy produced from the test burn) to PGE's 2014 NVPC forecast.

Q. Why was the 100 percent biomass test burn rescheduled to 2015?

A. The 100 percent test burn was rescheduled due to a lack of torrified biomass needed to conduct both the co-fire and 100 percent test burns. PGE expects to conduct the 100 percent test burn in 2015.

Q. How does PGE plan to incorporate the Boardman 100 percent biomass test burn costs into the 2015 test year?

A. The costs associated with only the Boardman 100 percent biomass test burn are included in PGE's NVPC forecast for the 2015 test year. This treatment is consistent with Staff's Report in UM 1571 provided in Order No. 12-141. 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. Is PGE double-collecting the costs of the Boardman 100 percent biomass test burn?

A. No. As stated above, there are two phases of the biomass test burn, the co-fire test and the 100 percent biomass test. Since the 100 percent test cost and energy were removed from the 2014 NVPC proceeding, the costs will not be collected from customers in 2014 rates. Thus, there is no double collection.

Q. What effect does the 100 percent biomass test burn have on PGE's initial 2015 NVPC forecast?

A. The Boardman 100 percent biomass test burn increases PGE's initial 2015 NVPC forecast by approximately $2.7 million. This estimate represents the net cost (fuel and associated costs less market value of energy produced) of the 100 percent test burn.

C. Transmission

1. Transmission Service Requests

Q. Have there been any decreases to PGE's existing transmission service requests since the 2014 NVPC proceeding?

A. Yes. At the end of 2014 or during 2015, many of PGE's existing transmission service requests (TSRs) on BPA's system will reach their termination date. This gives PGE the option to either rollover and extend our existing BPA TSRs (i.e., maintain our existing rights on BPA's transmission system) or let the TSRs expire (i.e., release our existing rights). PGE has already decided to allow 240 MW of TSRs to expire during 2015. The MFR documentation contains the current status of which TSRs have been renewed and the expiration dates for the TSRs.

Q. Has PGE made any additions to the transmission portfolio since the 2014 NVPC proceeding?

A. Yes. Aside from the new transmission associated with Tucannon and the increased share of Boardman discussed above, PGE has entered into a third-party contract for the purchase of additional PTP transmission for 2015. The details of the contract are discussed in the MFRs.

Q. Why is PGE changing its transmission portfolio?

A. The primary factors driving the changes to PGE's transmission portfolio are:

- Increased transmission associated with PGE wind resources;
- Addition of new generating resources; and,

- BPA policy changes.

Another contributing factor is the decreasing capacity available to PGE over time at the Mid-C via our hydro contracts. We discuss each of these factors and how they affect transmission resale opportunities in more detail below in the Transmission Resale Net Revenue subsection.

Q. How does MONET calculate the costs of transmission?

A. MONET calculates the monthly cost of transmission for each contract as the product of the applicable BPA rate (Point-to-Point, Scheduling Control and Dispatch, etc.) and PGE's capacity or demand for that contract.

Q. What effect does the change in transmission rights have on PGE's initial 2015 NVPC forecast?

A. The change in transmission rights decreases PGE's initial 2015 NVPC forecast by approximately $3 million. The reduction to NVPC is the result of the decrease in PGE's transmission capacity (140 MW net reduction), not a change in the transmission rates charged by BPA. We discuss the BPA PTP rate forecast below.

Q. Does PGE anticipate any other changes to its transmission rights in this proceeding?

A. PGE continues to evaluate its transmission portfolio in order to provide the most benefit to customers while still being able to meet load and reliability requirements. As identified in Section I, we plan to update transmission contracts in each of our scheduled update filings during this proceeding if new information becomes available.

2. Transmission Resale Net Revenue

Q. Please define transmission resale net revenue in this context.

A. As stated in the joint testimony supporting the stipulation reached in Docket No. UE 266 (Stipulating Parties/100/p. 13/lines 7-10):

> *PGE transmits power to its customers using BPA Point-to-Point (PTP) transmission contracts. When opportunities arise, PGE can "resell" these transmission rights on a short-term basis. While these sales generate incremental revenues, the sales are not typically costless to transact.*

Q. In the 2014 NVPC proceeding, what did the stipulating parties agree to with respect to transmission resale net revenue?

A. The stipulating parties agreed that PGE will include a proposed forecast of transmission resale net revenue in this filing and an explanation of how the forecast was created.

Q. How did PGE forecast transmission resale net revenue for 2015?

A. The forecast of transmission resale net revenue is based on counterparty indications of forward purchases for shoulder months and the amount of transmission rights PGE has available that are in excess of our needs during these periods. The details of these estimates are provided in the MFRs.

Q. Is PGE's forecast of transmission resale net revenue affected by the change in PGE's transmission portfolio?

A. Yes. As stated previously, PGE expects transmission resale revenues to be greatly reduced in the 2015 test year due to the three major factors identified in the TSR update subsection of our testimony (see above). We discuss each factor in more detail below. Although the opportunity for transmission resale may be reduced, changes to our transmission portfolio will provide benefits to customers via reduced transmission costs and more efficient transmission usage while allowing PGE to maintain the high level of reliability needed to provide our customers with excellent service.

Q. Please discuss the first factor, increased transmission associated with PGE wind resources.

A. Beginning in 2015, PGE's transmission portfolio will become more wind centric. PGE will have approximately 717 MW of transmission associated with wind resources and due to the variable nature of wind, this transmission will be primarily reserved for our wind plants and will have limited opportunity for resale.

Q. Please discuss the second factor, the addition of new generating resources.

A. PW2 and Tucannon will come online in 2015 and add approximately 487 MW of nameplate capacity to our system. Also, PGE's new base load energy resource, Carty, is planned to come online in 2016. These new resources will reduce PGE's load-resource gap. This increase in generation resources, coupled with reducing capacity available to PGE from our Mid-C hydro contracts, necessitates a shift toward a transmission portfolio that is more directly linked to our generation resources. In the 2015 test year and beyond, our generation resources will be more concentrated at the Slatt and Trojan Substations. Because of this, and the reduced Mid-C capacity available, PGE will have less non-generation-specific transmission available for resale, with much of the transmission available for resale being held in reserve for load balancing and flexibility needed to address the variability of wind resources.

Q. Please discuss the last factor, expected BPA policy changes.

A. PGE has been actively participating in several regional BPA forums. From discussions at these forums, BPA is pursuing policy changes that we expect to significantly impact the redirect and resale of PTP transmission.

Due to increasing use and congestion of the BPA transmission system, BPA has instituted new flow gates (i.e., metered choke points on BPA's transmission system). Historically, regional contract holders of BPA PTP transmission have had the right to unlimited hourly firm redirects on BPA's system. However, the new flow gates will affect transmission resale by restricting PTP transmission holders from unrestricted firm redirects and increasing the likelihood of lower priority secondary sales (e.g., transmission resale) being curtailed.

The new BPA flow gates increase the likelihood of curtailment for secondary sales in two ways. First, the flow gates restrict the amount of firm redirects that can be made by existing contract holders. Due to the decreased amount of firm redirects, secondary sales move up on the priority list of transmission required to be curtailed in congestion situations. This reduces the demand in the secondary market for purchasing PGE's excess PTP transmission because there is a significant increase in the likelihood of curtailment. Second, those purchasing PGE's PTP transmission with the intent to redirect may be required to compete for capacity at flow gates and could potentially purchase a product that has less margin of utility if the purchaser loses that competition. We discuss competition for redirects in more detail below.

In compliance with FERC Order 890-A, BPA has implemented Preemption and Competition for specific transmission paths based on new reservation requests. Based on PGE's participation in the regional forums, BPA also intends to implement competition for transmission redirects. BPA's proposal is that if a redirected TSR loses a competition (i.e., another entity submits a request for the same path for a longer duration or a higher need), the redirected transmission customer will not only lose the rights to the redirected path, but also the parent path (i.e., the original transmission path). This increased risk of loss for redirect customers will decrease the number of customers seeking to purchase PGE's transmission available for resale. Currently, BPA is seeking clarification from FERC on how to proceed with competition for transmission redirects. PGE continues to monitor the situation via attendance at the regional forums and communications with BPA.

Q. What effect does the forecast of transmission resale net revenue have on PGE's initial 2015 NVPC forecast?

A. Including a forecast of transmission resale net revenue decreases PGE's initial 2015 NVPC forecast by approximately $0.7 million.

3. BPA Point-to-Point Escalation

Q. Please describe the previous methodology for modeling BPA Point-to-Point rates in MONET.

A. Previously, BPA PTP rates were modeled based on actual rates through the end of the most recent BPA rate period. For months beyond the end of the BPA rate period, the PTP rate was forecasted based on historical escalation of rates from October 2001 through the current period. In this proceeding, the current BPA rates are effective through September 2015. Forecasted values are used for Q4 of 2015.

Q. What change does PGE propose to this method?

A. For the months beyond the end of the BPA rate period (i.e., Q4 2015), PGE proposes to use BPA's forecast of the PTP escalation for the next rate period instead of the historical escalation. A document with BPA's forecast is provided in the MFR documentation.

Q. What effect does the BPA PTP rate update have on PGE's initial 2015 NVPC forecast?

A. Updating the BPA PTP rate estimate for Q4 increases PGE's initial 2015 NVPC forecast by approximately $0.6 million.

Q. Does PGE plan to update this estimate during this proceeding?

A. We will update the PTP rate estimate as more information becomes available in order to produce the most accurate estimate.

D. Colstrip Unit 3 and Unit 4

1. Fuel Cost Allocations

Q. Please briefly explain the previous modeling of the Colstrip fuel cost allocations in MONET.

A. Each year Western Energy (the Colstrip mine operators) releases an Annual Operating Plan (AOP) that is used to allocate coal and transportation costs as either fixed or variable costs. The AOP determines fixed and variable costs by using categories that are specified in a contract. Previously, these costs were modeled in MONET based on the AOP allocations, with the variable portion translated to a $/MMBtu cost for plant dispatch.

Q. What does PGE propose to change about this methodology?

A. We propose to base the allocations of fixed and variable costs on new calculations provided by PPL Montana (the Colstrip Operators). These calculations are based on the same totals as the AOP, but with a reassignment of some costs from variable to fixed to better align with how Western Energy bills the owners of the Colstrip plant.

Q. Why is this new method better for modeling the Colstrip fuel cost allocations?

A. As previously stated, the new allocations from PPL Montana more accurately represent how Western Energy bills the owners of the plant. The new allocations provide a better estimate of costs that are incurred by dispatch of the plant and those that are fixed costs.

Q. What effect do the new fuel cost allocations for Colstrip Unit 3 and Unit 4 have on PGE's initial 2015 NVPC forecast?

A. The new fuel cost allocations for the Colstrip Unit 3 and Unit 4 decrease PGE's initial 2015 NVPC forecast by approximately $0.4 million.

2. Non-Running Station Service (NRSS)

Q. What NRSS is currently modeled in MONET?

A. NRSS is currently modeled for the following thermal plants: Boardman, Beaver, Coyote, and Port Westward 1. Additionally, in this proceeding, NRSS is included for Biglow Canyon, Tucannon, and for Colstrip Unit 3 and Unit 4.

Q. What NRSS load does PGE propose to model for Colstrip Unit 3 and Unit 4?

A. We propose to model an NRSS load of approximately 2.6 MW for each unit. This estimate is based on data from mid-2009 through 2012 and represents PGE's share of NRSS for each unit.

Q. How does PGE propose to model Colstrip NRSS in MONET?

A. The NRSS need for each unit is modeled in MONET using the same methodology as Boardman. This estimates a monthly NRSS energy need based on plant dispatch, maintenance, and forced outage rates. The NRSS energy is then shaped as flat across all hours of the month.

Q. Does PGE plan to update this estimate during this proceeding?

A. In past GRC proceedings, PGE has reviewed and updated thermal NRSS for the April filing. We plan to continue this practice for the Colstrip Unit 3 and Colstrip Unit 4 NRSS.

Q. What effect does NRSS for Colstrip Unit 3 and Unit 4 have on PGE's initial 2015 NVPC forecast?

A. Colstrip NRSS increases PGE's initial 2015 NVPC forecast by less than $0.1 million.

E. Wind

1. Biglow Canyon NRSS

Q. What was the previous estimate of NRSS for Biglow Canyon?

A. NRSS for Biglow Canyon was not previously modeled in MONET. Previously, NRSS was provided by a local PUD and accounted for through the plant's O&M budget. Due to a rate increase from the local PUD, PGE transitioned to supplying Biglow Canyon NRSS from the Mid-C when Biglow Canyon was offline by back-feeding from the transmission system through the plant's step-up transformers.

Q. What estimate of NRSS does PGE use in this filing?

A. We model the NRSS load for Biglow Canyon at 3 MW for hours when full plant generation is less than 1 MW. The 3 MW load is what PGE schedules for delivery to Biglow Canyon for NRSS hours. Historical generation data from Biglow Canyon Phase 1 from 2008-2012 and from Biglow Canyon Phase 2 and Phase 3 from 2011-2012 is used to calculate a five-year moving average of the monthly hours of NRSS need, based on the hours when full plant generation was less than 1 MW.

Q. Why does PGE use a five-year average instead of the four-year average used for thermal NRSS?

A. We use a five-year average because it is consistent with the five-year moving average methodology used in MONET to forecast generation at Biglow Canyon and Tucannon.

Q. What effect does NRSS for Biglow Canyon have on PGE's initial 2015 NVPC forecast?

A. Biglow Canyon NRSS increases PGE's initial 2015 NVPC forecast by approximately $0.2 million.

Q. Does PGE plan to update this estimate during this proceeding?

A. Similar to thermal NRSS, PGE plans to review and, if needed, update NRSS at Biglow Canyon for the April filing.

2. Wind Day-Ahead Forecast Error

Q. Please briefly explain the cost of wind day-ahead forecast error.

A. The cost of wind 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 forecasts 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 day-ahead forecast error has been included in the NVPC forecast by PGE since the 2008 test year in Docket No. UE 188. In the stipulation reached in the 2014 NVPC proceeding, the Stipulating Parties agreed that PGE will include and discuss in our initial 2015 power cost testimony our proposed updates to the wind day-ahead forecast error cost.[4]

Q. What was the previous estimate of the cost of wind day-ahead forecast error?

A. In the stipulation reached in the 2014 NVPC proceeding, the Stipulating Parties agreed to use an estimate of $0.87 per MWh.

Q. What estimate of the cost of wind day-ahead forecast error do you include in this initial 2015 NVPC forecast?

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[4] UE 266/Stipulating Parties/100/Crider-Jenks-Weitzel-Deen-Lindsay/9/7-15

A. In this initial filing, we use a wind day-ahead forecast error cost estimate of approximately $0.50 per MWh. This estimate was generated by the most recent model run of the Resource Optimization Model (ROM) used for PGE's wind integration studies.

Q. What effect does the wind day-ahead forecast error cost estimate update have on PGE's initial 2015 NVPC forecast?

A. Updating the wind day-ahead forecast error cost estimate does not significantly affect PGE's initial 2015 NVPC forecast. This insignificant NVPC change is based on the difference between the estimate used in this initial filing, <u>approximately</u> $0.50 per MWh, and the estimate that would have been used if PGE had not provided an updated estimate, <u>exactly</u> $0.50 per MWh, as agreed upon in the stipulation reached in Docket No. UE 266.

Q. Does this estimate include the effects of PW2 and Tucannon?

A. No. The estimate given above is the wind day-ahead forecast error cost for PGE's system <u>absent</u> PW2 and Tucannon. PW2 will decrease the wind day-ahead forecast error cost from approximately $0.50 per MWh to approximately $0.45 per MWh. The resulting reduction in NVPC is a component of the overall NVPC reduction from PW2 discussed previously. Tucannon, however, will increase the day-ahead forecast error cost from approximately $0.45 per MWh to approximately $0.46 per MWh. The resulting increase in NVPC is a component of the overall NVPC reduction from Tucannon discussed above.

Q. Does PGE plan to update this estimate during this proceeding?

A. Yes. As in past GRC and AUT proceedings, in the April filing we 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; and wind resource energy forecasts. Some of these updates will carry over to the ROM used to produce the wind day-ahead forecast error cost estimate.

Q. Will PGE provide the updated wind day-ahead forecast error cost estimate in the April filing?

A. No. Due to the run-time of the ROM, the data input process, and the time needed for validation of the inputs and results, we do not anticipate having a final estimate of the updated wind day-ahead forecast error cost in time for the April filing. We propose to provide the parties of this proceeding with the updated estimate and an explanation of input changes via a letter sent by May 31. The purpose of this letter is to provide parties with adequate time and opportunity to review the updated estimate before it is incorporated in MONET for the July filing.

F. WECC Reserve Requirement

Q. Please describe the 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. FERC approved the new WECC standard for operating reserves on November 21, 2013 (FERC Order No. 789). The new standard became effective January 28, 2014[5] and FERC will begin enforcing compliance on October 1, 2014.

Q. What effect does the new standard have on PGE's initial 2015 NVPC forecast?

[5] 145 FERC ¶ 61,141, United States of America, Federal Energy Regulatory Commission

A. The new standard increases PGE's initial 2015 NVPC forecast by approximately $0.13 million.

G. Oil Forward Price Basis Differential

Q. How does MONET use the oil forward price?

A. MONET uses the oil forward price to determine the total cost of fuel oil consumed at the Boardman and Colstrip plants for startup, testing, and other purposes. The oil forward price is also used by MONET to determine the costs associated with Beaver testing and Dispatchable Standby Generation monthly testing.

Q. What are the components of the oil forward price?

A. We start with the Chicago Mercantile Exchange (CME) New York Harbor No. 2 Heating Oil Futures price (formerly NYMEX). We then add a basis differential between Portland and New York Harbor to arrive at the Portland forward price.

Q. How was the previous estimate of the basis differential determined?

A. The basis differential between Portland and New York No. 2 was computed by taking the 12-month average of the average estimated monthly bases from January 2003 through October 2004.

Q. How did PGE develop the updated basis differential used in this filing?

A. The basis differential is updated based on the NY Harbor Heating Oil daily spot prices and the Portland Wholesale B2 Soy Methyl Ester (SME) daily spot prices. We calculate the basis differential ($/gallon) as the one-year average of the differences between the Portland B2 and NY Harbor Heating Oil daily spot prices (Portland B2 less NY Harbor). The NY Harbor Heating Oil spot prices are from the Energy Information Administration (EIA) and the Portland B2 SME spot prices are from the Oil Price Information Service (OPIS). For this filing, the basis differential is calculated using 2012 data.

Q. What effect does updating the oil forward price basis differential have on PGE's initial 2015 NVPC forecast?

A. Updating the oil forward price basis differential increases PGE's initial 2015 NVPC forecast by approximately $0.03 million.

Q. Does PGE plan to update the basis differential estimate during this proceeding?

A. Yes. PGE plans to update this estimate with 2013 data in the April filing when we update the oil forward price curve.

H. 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 2011–2012 Study to the 2012–2013 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 2015 NVPC forecast?

A. Updating the PNCA study increases PGE's initial 2015 NVPC forecast by approximately $0.19 million.

I. Forthcoming Updates

Q. Does PGE expect to update any items in future filings in this proceeding?

A. We expect to 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 make any errata corrections to this initial filing in the April 1 filing. This is standard practice during a GRC proceeding.

Q. Are there other items that PGE expects will require updates?

A. Yes. PGE expects to update the following:

- Inclusion of the integration benefits from PW2 during Q4 of 2015 in the April 1 filing.
- The Tucannon energy forecast and shaping in the October filing.
- The wind day-ahead forecast error cost estimate after the April 1 filing. As discussed above, PGE will provide parties with notice of the updated estimate prior to the July filing to allow for adequate review time.
- An agreement, should it be reached, for PGE to acquire Power Resource Cooperative's (PRC) 10 percent ownership share of the Boardman plant in the April 1 filing. PGE Exhibit 800 discusses PGE's potential acquisition of the PRC ownership share in more detail.
- The potential long-term extension of PGE's contract to purchase the output from the Confederated Tribes of the Warm Springs Reservation of Oregon (Tribes) 33.33 percent

ownership share of the Pelton and Round Butte plants (PRB) and all of the net output of the Tribes' Re-regulation plant (Re-reg).

Q. Please describe PGE's current agreement with the Tribes.

A. PGE and the Tribes are co-owners of PRB, with the Tribes owning 33.33 percent of PRB and 100 percent of Re-reg. PGE is the operator for all three plants. Under the Ownership and Operation Agreement (OOA), each year PGE purchases the full output of the Tribes' 33.33 percent share of PRB and all of the net output of Re-reg.

Q. Why are PGE and the Tribes exploring a long-term contract extension?

A. Under the OOA, the Tribes have the right, on a one-time basis, to sell their one-third share of the output of PRB and the net output of Re-reg to a third party, provided that the Tribes give notice to PGE by April 1 of the prior year. Once the Tribes provide notice to exercise their right to sell, the Tribes no longer have an obligation to sell their share to PGE and PGE no longer has an obligation to purchase. Warm Springs Power and Water Enterprises (WSPWE), the entity that manages the Tribes' shares and interest in PRB and Re-reg, informed PGE of their intention to explore their rights to sell their share of the output beginning in 2015 via an auction process. PGE and WSPWE agreed to begin discussing the potential for a long-term extension of the contract while WSPWE evaluated the auction option.

Q. Please describe the main components of the potential long-term contract extension.

A. PGE and WSPWE are in negotiations for PGE to continue to purchase all of the output from the Tribes' 33.33 percent share of PRB and 100 percent of the net output of Re-reg. A summary of the potential extension is below.

- Ten years, beginning in 2015.

- Approximately 160 MW of capacity with an expected annual energy of 65 MWa through 2022. If the Tribes exercise their rights to purchase an additional 16.66 percent ownership share of PRB, the capacity would increase accordingly for 2023 and 2024.
- During the term of this extension, the Tribes will forego their rights to sell their share of the PRB and Re-reg output to a third party.

Q. What are the benefits of the long-term contract extension?

A. PRB is the only PGE-owned hydro resource that provides usable and substantial reservoir storage and shaping capability. PRB also provides regulation and load-following services and a portion of PGE's owned capacity is used to meet reserve requirements. As described above, upon execution of the extension, the Tribes will forego their right to sell their share to a third party for ten years. This will ensure that customers have continued access to flexible hydro generation during a time when PGE's Mid-C hydro contracts are diminishing.

Q. What is the current status of the negotiations with WSPWE?

A. PGE and WSPWE have reached an agreement on the basic structure and key terms and conditions of the long-term contract extension. If agreement can be reached on the final terms and conditions, then we anticipate executing the contract extension by April 2014.

Q. If an agreement is reached, would PGE update its filing?

A. Yes. PGE will submit supplemental testimony, supporting work papers, and an updated revenue requirement by April 1, 2014 to reflect the final terms and costs, including the effect on the 2015 NVPC forecast.

Q. Did PGE issue an RFP for the output acquired in the long-term contract extension?

A. No. This is an extension of an existing agreement between PGE and the Tribes. PGE will continue to purchase the same amount of energy from the Tribes that it has purchased over the previous twelve years and that PGE would have continued to purchase under the terms of the OOA, absent the Tribes notice. Because this is an extension of an existing agreement and will not result in PGE acquiring any additional energy beyond what it would have acquired under the OOA, we believe that the RFP requirements do not apply.

J. Changes to Schedule 125 and Schedule 126

Q. Does PGE propose adjustments to Schedule 125 to reflect the updates discussed above?

A. Yes. We propose one change to Schedule 125 in order to reflect the inclusion of reciprocating engine lubrication oil at PW2 in NVPC as discussed above.

Q. Does PGE propose adjustments to Schedule 126?

A. Yes. Our proposed change to Schedule 126 updates the definition of NVPC for inclusion of the costs of reciprocating engine lubrication oil consumed at PW2, consistent with our proposed change to Schedule 125. Additional changes related to PGE's proposal to carve out renewables from the PCAM are discussed below in Section VI and in PGE Exhibit 1400.

IV. UE 266 Stipulation

A. BPA Variable Energy Resource Balancing Service Election

Q. What is the status of the workshops on BPA's April 2014 mid-rate-period election opportunity for integration services?

A. In Docket No. UE 266, PGE agreed to meet with RNP at least twice, no later than December 2013 and March 2014, to present PGE's analysis of its election for BPA's April 2014 mid-rate-period election opportunity and all other parties will be invited. PGE held the first workshop regarding the mid-rate-period election opportunity on December 17, 2013. An invitation to the workshop was sent to the service list for Docket No. UE 266. The second workshop is planned for mid-March 2014.

Q. Please describe the nature of PGE's analysis of the April 2014 mid-rate-period election opportunity.

A. In conducting this analysis, PGE evaluates the following:

- the current environment, including sub-hourly market development and requirements, and potential Energy Imbalance Markets (EIMs);
- capacity needs;
- transmission requirements, availability, and flexibility;
- necessary system upgrades, such as Automatic Generation Control (AGC) and a platform to dynamically dispatch AGC plants in real-time;
- the potential costs, such as cycling costs, wear and tear costs, and capital costs; and,
- the potential benefits of electing a shorter scheduling paradigm.

Q. Please generally describe the current status of PGE's analysis of the April 2014 mid-rate-period election opportunity.

A. PGE is in the process of updating the previous analysis used to make the Variable Energy Resource Balancing Service (VERBS) election for Biglow Canyon in April, 2013 for the 2014-2015 BPA rate case period. Potential updates include:

- new BPA rate structures for mid-rate-period as proposed during the BPA Generation Inputs Settlement;
- potentials changes to BPA business practices, including 15-minute scheduling;
- sub-hourly transmission product availability; and,
- intra-hour market potential analysis.

As new information becomes available, it will be incorporated into the analysis and used to inform the decision regarding the upcoming mid-rate-period election.

Q. What VERBS service does PGE use in its initial 2015 NVPC forecast?

A. We use the BPA VERBS Base Service rate for 30/60 committed scheduling in our initial 2015 NVPC forecast.

B. Five-year Moving Average Forecast

Q. How was PGE's forecast of Biglow Canyon wind energy output developed in the 2014 NVPC proceeding?

A. PGE developed a forecast for the output of each phase of Biglow by using the five-year moving average methodology discussed in PGE's testimony in Docket No. UE 262, Exhibit 400, page 9 at line 15:

> *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. Does PGE use the same five-year moving average methodology used in the 2014 NVPC proceeding to forecast Biglow Canyon wind energy in this proceeding?

A. Yes. As discussed above, we continue to use and support the five-year moving average methodology to forecast Biglow Canyon and Tucannon wind energy. For this initial filing, full-year actual generation data for each Phase of Biglow Canyon through year-end 2012 are used. In the April filing, we will incorporate actual generation data through year-end 2013 into the five-year average.

Q. Did PGE hold a workshop to discuss the five-year moving average methodology with parties?

A. Yes. PGE held a workshop on October 10th, 2013. Representatives from CUB, ICNU, OPUC Staff, RNP, and other parties were in attendance or participated via conference call. PGE offered to hold additional workshops if needed, but none was requested by parties.

V. Comparison with 2014 NVPC Forecast

Q. Please restate PGE's initial 2015 NVPC forecast.

A. The initial forecast is $580.2 million.

Q. How does this 2015 NVPC forecast compare with the 2014 forecast used to develop NVPC in Docket No. UE 266 and approved in Commission Order No. 13-280?

A. Based on PGE's final updated MONET run for the 2014 test year, the NVPC forecast was $621.7 million, or $32.96 per MWh. The initial 2015 forecast (excluding PGE's new resources) is $593.4 million, or $31.55 per MWh, which is approximately $1.41 per MWh less than the final forecast for 2014. Including PW2 decreases PGE's initial 2015 forecast to $592.2 million, or $31.49 per MWh. Including both PW2 and Tucannon decreases PGE's initial 2015 forecast to $580.2 million, or $30.85 per MWh.

Q. What are the primary factors (excluding PGE's new resources) that explain the decrease in NVPC forecast for 2015 versus the NVPC forecast for 2014 in Docket No. UE 266?

A. As Table 1 demonstrates, multiple factors contribute to the decrease:

Table 1
Factors in Forecast Power Cost Difference 2015 vs. 2014
($ Million)

Element	**$ Effect***
Hydro Cost and Performance	4.9
Coal Cost and Performance	-1.9
Gas Cost and Performance	-23.4
Wind Cost and Performance	0.5
Contract and Market Purchases	-13.7
Market Purchases for Load Change	-1.4
Transmission	-0.1
Increased Market Price	6.6
Total	**-28.3**

* Numbers may not total due to rounding.

Key among these factors is the significant reduction in power costs related to gas-fired generation and increased market purchases. Lower overall costs, on a $ per MWh basis, for PGE's gas-fired resources leads to a reduction to the NVPC forecast. Increased market purchases replace contract purchases and displace more costly resources, also reducing the NVPC forecast. However, these effects are partially offset by increases in market prices relative to PGE's final 2014 NVPC forecast in Docket No. UE 266.

VI. RPS Carve Out

Q. What is the RPS Carve Out?

A. It is PGE's proposal to establish a practice of "carving out" renewable resources from the Power Cost Adjustment Mechanism (PCAM) and passing the incremental benefits and costs of those resources through the Renewable Resources Automatic Adjustment Clause tariff ("RAC", Schedule 122).

Q. Why is an RPS carve out appropriate?

A. It provides PGE the opportunity to recover all prudently incurred costs associated with compliance with the Oregon RPS.

Q. What is the basis for PGE's proposal?

A. Enacted in 2007 through Senate Bill 838 (SB 838), codified in ORS 469A, the RPS requires Oregon utilities to deliver a percentage of their electricity from renewable resources. For utilities such as PGE, the percentage of renewables rises periodically until it reaches 25 percent beginning in 2025. PGE's proposal is based on the clear language of SB 838, Section 13, part 1 which states:

> "… all prudently incurred costs associated with the compliance with a renewable portfolio standard are recoverable in the rates of an electric company…"

SB 838 goes on to elaborate on the types of related costs that should also be recoverable:

> "…including interconnection costs, costs associated with using physical or financial assets to integrate, firm or shape renewable energy sources on a firm annual basis to meet retail electricity needs and other costs associated with transmission and delivery of qualifying electricity to retail electricity customers."

This language can be found in ORS 469A.120.

Q. Does the current regulatory framework allow for these costs to be fully recovered?

A. No. The current regulatory framework allows for a level of costs and benefits to be included in customer prices as part of a regulatory proceeding such as a general rate case or annual update tariff filing. However, these forecasts often vary significantly from actuals due to uncontrollable circumstances such as weather conditions. For instance, wind generation may be greater than or less than forecasted, reducing or increasing PGE's overall net variable power cost and the amount of production tax credits generated. Additionally, PGE must continue to make investments in renewable resources, such as Tucannon, to maintain compliance with the RPS which will exacerbate the issue with the current regulatory framework.

Q. Doesn't the Power Cost Adjustment Mechanism (PCAM) allow for these costs to be recovered?

A. Not all of them. Though it currently contemplates many of these costs, the PCAM does not allow PGE recovery of all prudently incurred costs associated with variable energy resources to meet Oregon's RPS. This is because the PCAM evaluates PGE's overall actual net variable power costs (NVPC) compared to the forecast established in the Annual Update Tariff (AUT). The variance is then subject to deadbands, an earnings test and sharing. Additionally, neither the PCAM nor AUT contemplate recovery of, or variations in, production tax credits (PTCs).

Q. Please describe the proposal.

A. PGE proposes to use the Renewable Adjustment Clause tariff (Schedule 122) to refund to or collect from customers variances in power (output, market value, integration and royalties) and related PTCs costs for RPS-compliant resources. The refund or collection via the RAC would be included as an adjustment to PGE's Results of Operations report, thereby reducing or increasing PGE's regulated return on equity for the year. Finally, the forecasted and actual power costs would be removed from the Power Cost Adjustment Mechanism (Schedule 126) for purposes of determining refunds or collections under the PCAM. Modified versions of Schedules 122 and 126 are included with this filing and can be found in PGE Exhibit 1400.

Q. Which resources would this proposal apply to?

A. PGE's proposal applies to renewable resources used for compliance with the RPS. Table 2 below contains a list of these resources.

Table 2
Renewable Resources

PGE Owned Assets:	PGE Contracts:
• Biglow Canyon • Tucannon River • Low Impact Hydro and Hydro Upgrades	• Vansycle Wind • Klondike Wind • Outback Solar • Bellevue Solar • Yamhill Solar • Sunway II & III

Q. Does this proposal alter the Annual Update Tariff?

A. No. PGE will continue to make annual net variable power cost filings.

Q. What process would this proposal follow?

A. We outline the steps below:

- PGE establishes a net variable power cost forecast for the test year (2015)
- PGE tracks actual costs for 2015
- In 2016 PGE calculates the variances between forecasted and actual costs related to renewable projects
- PGE files for inclusion of the variance in rates effective January 1, 2017
- This process repeats annually

Q. How will power cost variances be determined?

A. For PGE-owned resources such as Biglow, PGE will calculate the power cost variance by calculating the difference between forecasted and actual output and market prices. As applicable, PGE will also take the difference between forecasted and actual royalty payments and integration costs.

For contracted resources, PGE will calculate the power cost variance by calculating the difference between forecasted and actual output and margin. Margin will be calculated by taking the difference between the contract price and market price.

Table 3 below summarizes the variables used for developing the variances:

Table 3
Variables

Variables for determining the forecast	
PGE Owned Assets: • Hourly Generation from Final AUT filing • Hourly Market Prices from Final AUT filing • Monthly Royalty Payments (if applicable) • Monthly Integration Costs (if applicable)	PGE Contracts: • Monthly Generation from Final AUT filing (On-Peak and Off-Peak) • Contracted Price ($/MWh) by Month from Final AUT filing (On-Peak and Off-Peak) • Monthly Market Prices (On-Peak and Off-Peak)
Variables for determining actuals	
PGE Owned Assets: • Hourly Generation • Hourly Market Prices • Actual Monthly Royalty Payments and Integration Costs (if applicable)	PGE Contracts: • Monthly Generation (On-Peak and Off-Peak) • Contracted Price ($/MWh) by Month from Final AUT filing (On-Peak and Off-Peak) • Monthly Market Prices (On-Peak and Off-Peak)

PGE Exhibit 503 contains a more detailed explanation of the variance calculations.

Q. How will PTC variances be determined?

A. PGE will calculate the difference between actual PTCs generated and those forecasted to be generated in the most recent general rate case. The forecasted PTCs will be valued at the $/MWh rate used in the most recent general rate case while actual PTCs will be valued at the $/MWh rate as established by the Internal Revenue Service for the year in question.

Q. Will these variances accrue interest?

A. Yes. Variances will accrue interest at PGE's authorized cost of capital until the funds begin being amortized. While PGE's initial proposal calls for annual revisions to rates, a structure could be put in place to reduce the frequency of price changes for customers such as a dollar limit the accrued variances must reach before customers are credited or charged.

Q. Is PGE proposing modifications to the structure of its PCAM?

A. Not at this time.

VII. 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. 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. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
501	List of MFRs per OPUC Order No. 08-505
502C	February 13 Initial Filing MONET Output Files and Assumptions Summary
503	RPS Carve Out Variance Calculations

ORDER NO. 08-505

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

ORDER NO. 08-505

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.

Historical Operating Data

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 502C

Confidential

RPS Carve Out - Calculation Methodology

Resource	Forecast Calculation	Actual Calculation
Biglow & Tucannon Power Cost	[Hourly Generation * Hourly Price] + Integration Costs + Royalty Costs	[Hourly Scheduled Generation * Hourly Mid-C Price] + Integration Costs + Royalty Costs
Biglow & Tucannon PTC	Forecast Generation * PTC Rate	Actual Generation * PTC Rate
Vansycle Wind	[Monthly On-Peak Generation * (On-Peak Contract Price - On-Peak Mid-C Price)] + [Monthly Off-Peak Generation * (Off-Peak Contract Price - Off-Peak Mid-C Price]	[Monthly On-Peak Generation * (On-Peak Contract Price - On-Peak Mid-C Price)] + [Monthly Off-Peak Generation * (Off-Peak Contract Price - Off-Peak Mid-C Price]
Klondike Wind	[Monthly On-Peak Generation * (On-Peak Contract Price - On-Peak Mid-C Price)] + [Monthly Off-Peak Generation * (Off-Peak Contract Price - Off-Peak Mid-C Price]	[Monthly On-Peak Generation * (On-Peak Contract Price - On-Peak Mid-C Price)] + [Monthly Off-Peak Generation * (Off-Peak Contract Price - Off-Peak Mid-C Price]
Outback Solar	[Monthly On-Peak Generation * (On-Peak Contract Price - On-Peak Mid-C Price)] + [Monthly Off-Peak Generation * (Off-Peak Contract Price - Off-Peak Mid-C Price]	[Monthly On-Peak Generation * (On-Peak Contract Price - On-Peak Mid-C Price)] + [Monthly Off-Peak Generation * (Off-Peak Contract Price - Off-Peak Mid-C Price]
Bellevue, Yamhill & Sunway II&III	[Monthly On-Peak Generation * (On-Peak Contract Price - On-Peak Mid-C Price)] + [Monthly Off-Peak Generation * (Off-Peak Contract Price - Off-Peak Mid-C Price]	[Monthly On-Peak Generation * (On-Peak Contract Price - On-Peak Mid-C Price)] + [Monthly Off-Peak Generation * (Off-Peak Contract Price - Off-Peak Mid-C Price]
Low Impact Hydro & Hydro Upgrades	[Hourly Generation * Hourly Price] * Renewable Factor	[Hourly Actual Generation * Hourly Mid-C Price] * Renewable Factor

Renewable Factor = [Low-Impact MW + Upgrade MW] / [Plant Capacity MW]

Ownership	Contract

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 283

Total Compensation

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Arleen Barnett
Jardon Jaramillo

February 13, 2014

Table of Contents

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, managing employee development, employee relations, overseeing safety and health programs, and overseeing Business Continuity, Security, and Records Management.

My name is Jardon Jaramillo. My position is Director of Compensation and Benefits in the Human Resources 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 2015 test year and describes the changes to our compensation policies and plans since 2012. Total compensation costs include base wages and salaries, incentive pay, and employee benefits. We also present and explain PGE's proposed pension cost recovery.

Q. What are PGE's expected total compensation costs in 2015?

A. PGE forecasts approximately $323.0 million in total compensation costs for 2015, with the increase relative to PGE's 2014 budget driven primarily by health benefit related costs and wages and salaries. Table 1 summarizes the costs.

Table 1
Estimated Total Compensation Costs ($Millions)

Component	**2014 Budget**	**2015 Test Year**
Wages & Salaries	$223.4	$232.2
Incentives	8.6	8.9
Benefits	77.9	81.9
Total Compensation*	**$310.0**	**$323.0**

**Numbers may not sum due to rounding*

The increase in forecasted wages and salaries from 2014 to 2015 is due to market-driven wage and salary adjustments and increased labor requirements needed to accomplish PGE's business goals ($8.7 million). Test year incentive costs increase $0.3 million reflecting base labor escalation rates for 2015. Benefits reflect continued increases in medical premiums ($3.4 million).

Q. Why are you comparing the 2015 test year costs to the 2014 budget?

A. PGE's 2014 budget approximates final UE 262 costs that are currently in retail rates as approved by Commission Order No. 13-459 (issued December 9, 2013). As noted in PGE Exhibit 300, because we are holding PGE's overall 2014 budget flat to the final stipulated costs from UE 262, comparing the 2015 forecast to the 2014 budget reflects the most relevant cost increases.

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 continues to face four significant challenges:

(1) Recruiting;

(2) Rising health care costs;

(3) An experienced but aging workforce, resulting in an increasing and significant number of retirements; and

(4) Changes in legislation and regulations.

A. Recruiting

Q. Please describe the first challenge – recruiting.

A. PGE continues to face 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 potential 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 continued improvement in the job market, there is added pressure to not only attract the necessary skill sets needed at PGE, but also to retain these employees. Hiring for 2013 has increased considerably over 2012 due to increased retirements and employees leaving for other opportunities. With an improving economy and as changing technologies require new, in-demand skill sets, we expect recruiting challenges to continue.

Q. What is PGE's approach to the recruiting challenge?

A. 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. PGE also continues to support its employee development through educational assistance, mentoring and cross-trainings, which help to fill some senior level positions internally. We also have a popular summer hire program that helps to develop entry-level engineering, business, and other professional candidates.

B. Health Care Costs

Q. How does PGE combat the second challenge – rising health care costs?

A. PGE negotiates and implements new plans that offer cost efficiencies. For example, since we implemented our high deductible health care plans for Providence (2012) and Kaiser (2013) we have seen a noticeable shift in employee enrollments to these plans, which lowers company-paid healthcare costs. Additionally, PGE has developed and implemented 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 interest to minimize health care costs.

C. Aging Workforce

Q. Why do you consider PGE to have an aging workforce?

A. More than 40% 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 2015. With economic and market conditions continuing to improve, more and more eligible employees are choosing to retire. In 2010 there were 54 retirements; in 2012 this number nearly doubled to 102 retirements; and in 2013 the number was 126. Because a large portion of retirement eligible employees are working in highly specialized, senior level positions, this heightened level of retirements (which we expect to continue for a number of years) places additional strains on PGE's operations and recruiting efforts.

Q. How is PGE responding to the challenge of an aging workforce?

A. As a response to this fact, PGE continues to recruit externally as well as train internal employees (through our cross-training, educational assistance, and mentorship programs) 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.

D. Legislation and Regulations

Q. Please describe recent changes in legislation and regulations and what PGE is doing to lessen their impact.

A. Federal legislation including the Pension Protection Act and the Patient Protection and Affordable Care Act along with city regulation including the Portland Protected Sick Time Ordinance continue to have a significant impact on the costs of PGE's benefit plans. In response, PGE closed its pension plan to new hires, continues to redesign its medical plans (discussed in Section IV), and continues to negotiate with its service providers to lower administrative and plan management costs.

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 equivalent employees (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 expected to be 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, we then adjust (the "unfilled position 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 forecasted total FTEs (excluding overtime) for 2014 and 2015.

Table 2
Full-Time Equivalents

PGE FTEs (straight time)	**2014 Budget**	**2015 Test Year**
Administrative and General (A&G)	353.0	355.9
Information Technology (IT)	244.7	248.1
Customer Service/Accounts	506.1	506.3
Generation	501.7	509.8
Transmission & Distribution	950.2	946.7
Total FTEs*	**2,555.8**	**2,566.8**

**Numbers may not sum due to rounding*

Q. Please explain how FTEs have changed from 2014 to 2015.

A. Overall we expect to need 11 additional FTEs from 2014 to 2015. In A&G and IT the increases in FTEs are due largely to increases in business continuity and emergency

[1] All hours over 2080 per position, per year are excluded.

management (PGE Exhibit 700). Generation increases are largely due to the work related to Port Westward 2 and Tucannon River Wind Farm, PGE's new generation resources (PGE Exhibits 400 and 800). Transmission and distribution has offsetting reductions to FTEs due to the deployment of major projects reducing the need for FTEs related to project development (PGE Exhibit 900). Outside of these necessary changes, the overall number of FTEs needed for 2015 remains the same as forecasted for 2014. PGE Exhibit 601 provides a list of FTEs by department for 2011 (actuals) through 2015 (test year forecast).

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 2013, 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 3.91% increase in overall wages and salaries from 2014 to 2015. Table 3 summarizes total wage and salary costs for 2014 and 2015.

Table 3
Total Wages & Salaries ($000)

PGE Wages & Salaries (straight time)	**2014 Budget**	**2015 Test Year**
Administrative and General	$60,561	$62,784
Customer Accounts	26,444	27,744
Customer Service	9,339	9,965
Generation	44,792	47,369
Transmission & Distribution	82,312	84,306
Total Wages & Salaries*	**$223,449**	**$232,168**

**Numbers may not sum due to rounding*

Q. Has PGE made any adjustments to the 2015 FTEs and wages and salaries?

A. Yes. To account for vacancies and/or unfilled positions, PGE has lowered its base budget wages and salaries by $5.0 million. We also made a $1.0 million adjustment to reflect on-going savings expected from "myTime," PGE's new time collection system. The adjustment for vacancies and/or unfilled positions translates into a 54.8 overall FTE reduction, whereas the myTime (see PGE Exhibit 707 for further details) adjustment is strictly an adjustment to wages and salaries, not FTEs. Additionally, there is a wage escalation adjustment made to officer and exempt employee wages of approximately $1.0 million. The figures in Table 2 and Table 3 are net of these reductions.

III. Incentives

Q. What is 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, 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 50^{th} 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 2015 total compensation. Table 4 provides a detailed forecast for 2014 and 2015.

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	**2014 Budget**	**2015 Test Year**
Performance Incentive Compensation	$4,291	$4,471
Annual Cash Incentive	3,180	3,323
Stock (long-term incentive plan)	988	984
Notables and Miscellaneous	129	129
Total Incentives	**$8,558**	**$8,907**

**Amounts Exclude Port Westward 2 and Tucannon River Wind Farm*

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 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 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. 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. 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 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. Have there been any recent changes to the ACI plan?

A. Yes. Beginning in 2013, the weighting of the customer service, electric service power quality and reliability, and generation availability goals make up at least 50% percent of the overall plan goals. 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] Additionally, the overall customer satisfaction target has been increased by five percentage points. 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. Through changing the payout structure and increasing the difficulty of our customer satisfaction metric, 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 2012 remain in effect. We have found these plans to be effective in motivating employees to pursue efficiencies, enhance their professional development, and maintain a high level of operations.

[2] OPUC Order No. 97-171, p. 74

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 No. 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 $984,000 for the 2015 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 2015 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 2015 test year.

[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 5.0% from 2014 to 2015, driven primarily by health costs. This and other drivers are discussed in more detail below and in Section V. We project 2015 employee benefit costs of approximately $81.9 million.

Table 5
Total Benefits ($000)

Benefits Compensation Component	**2014 Budget**	**2015 Test Year**
Health and Wellness	$39,654	$43,050
Disability and Life Insurance	3,750	3,870
Post-Retirement	33,241	33,633
Miscellaneous Benefits	728	743
Benefits Administration	573	588
Total Benefits*	**$77,947**	**$81,884**

**Numbers may not sum due to rounding*

***Amounts Exclude Port Westward 2 and Tucannon River Wind Farm*

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. In 2012, we switched vendors for our Medicare supplement plan, resulting in lower company contributions to the plan, saving approximately $0.5 million for 2015. Additionally, as we noted previously, when health care premiums rise, PGE employees share the increased cost.

PGE also redesigns and adjusts program features to help control costs through shifting a greater share of the burden on to employees. For 2014 and 2015, the redesign includes doubling the employee deductible for Providence plans and increasing the co-insurance across the plans offered. Additionally, the deductible for all Providence Plans will apply to out-of-pocket maximums. PGE also offers high deductible health plans (HDHPs) through Providence and Kaiser that benefit both PGE and employees through lowered premiums as employees pay a greater share of post medical expenses. With these changes and previous redesigns, the budget for health and dental expenses has been reduced by approximately $1.4 million.

PGE also compares outside services and insurance versus our own in-house capabilities and self-insurance. As a result, in 2011, PGE moved to an in-house health and welfare administrative system that continues to save $0.3 million annually by leveraging our existing capabilities.

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 having a high risk of health problems during our health screenings to lower their medical risks (e.g., diabetes, heart disease, high cholesterol, high blood pressure, etc.). PGE's medical vendors also provide and encourage participation in wellness programs and disease management programs. These programs are designed to 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 $3.4 million from 2014 to 2015.

A. Medical and dental costs continue to rise each year nationwide, not just in the Northwest or at PGE. The Brookings Institute estimates that healthcare spending will outpace GDP growth by 1.2% annually[4]. This $3.4 million requested increase for medical and dental represents a 4.8% annual increase from 2012. This is down significantly from PGE's annual increase of 6.2% from 2006 to 2012 and in line with the Global Insight estimated annual increase of 4.2% from 2012 to 2015[5]. 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://www.brookings.edu/about/projects/bpea/latest-conference/2013-fall-chandra-healthcare-spending
[5] IHS Global Insight, US Economic Outlook dated January 2014

Table 6
Non-bargaining Medical & Dental Premium (% change)

	2012	**2013**	**2014**	**2015****
Kaiser Medical	9.0%	7.7%	-6.0%	7.5%
Kaiser HDHP	N/A	N/A	-5.6%	7.5%
Kaiser Dental	0.0%	-5.2%	7.3%	7.5%
Providence*	19.8%-22.1%	1.8%-8.3%	3.1%-3.2%	9.0%
Providence HDHP		0.0%	8.5%	9.0%
MetLife Dental	6.1%	4.2%	0.0%	6%

**Providence has 3 different plans. The changes above are ranges among the 3 plans.*
***2015 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 10.7% in 2014 and 9.0% in 2015, based on a semi-annual survey of local insurance companies' annual claims cost trends performed by Mercer (PGE's benefits consultant) and actual employee experience in 2012 and 2013.

Q. Have there been any legislative changes affecting health care costs?

A. Yes. Beginning in 2014, all temporary employees working at least 20 hours per week are eligible for medical benefits after 60 days of employment at PGE. Additionally, as health care reform continues to be rolled out over the next four years, PGE expects to see significant changes to its medical plan design in order to manage costs.

Q. What wellness expenses are included in the 2015 test year?

A. PGE forecasts approximately $0.3 million for wellness costs in 2015. Our wellness programs 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. Some of the services provided through these health programs include biometric testing, health risk appraisals, professional health coaching, obesity management, wellness reimbursements and disease prevention. Also included are occupational health services, which provide flu shots, health screening, and case management.

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 serve to reduce PGE's total medical costs by shifting a greater percentage of post-care costs over to employees.

Q. How do PGE's overall benefit costs compare to market benchmarks?

A. Based on the Towers Watson 2013 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 continues to be at the industry average for its overall benefit programs. These results are in line with PGE's approach of providing a competitive, yet cost effective overall benefit package to assist with retention and recruitment of qualified and committed employees. While bargaining employees continue to rank slightly higher than the BENVAL average, their reduction to 2013 and 2014 wage increases (as agreed to in the 2012 extension to the collective bargaining agreement in trade for maintaining a 90/10 medical benefits cost sharing structure) offsets their higher than average medical benefits.

Q. Please explain PGE's 2015 disability and life insurance benefit forecast of $3.9 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.

Additionally, consistent with Generally Accepted Accounting Principles (GAAP), beginning in 2014, PGE has moved the compensable hour contribution associated with union employee health reimbursement accounts (HRA) ($1.00 per straight-time hour as prescribed in the current collective bargaining unit agreement) into the long-term disability account.

PGE forecasts union short-term disability (STD) insurance costs of approximately $559,000 in 2015. This represents a $48,000 increase from 2014 and is the result of a 10% rate increase in the renewal of the union short-term disability contract in the middle of 2014, coupled with union wage increases for 2014 and 2015. Costs for 2014 and 2015 reflect our claims history. Additionally, beginning in 2014, the Portland Protected Sick Time Ordinance[6] has increased short-term disability costs by requiring PGE to provide STD pay to new employees upon starting at the company, rather than after six months of employment. 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 $2.2 million in 2015. 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.

[6] http://www.portlandoregon.gov/sicktime/

PGE forecasts retiree group life insurance costs to be approximately $1.1 million in 2015. 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.[7]

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 2014 to 2015, costs associated with the RSP are expected to increase from $16.1 million to $16.7 million, or approximately 3.6%. 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 unit employees, the compensable hour contribution has been moved into post-retirement benefits (as described above). Additional union HRA costs relate to the accumulation of notional hours for current employees and retirees receiving current HRA

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[7] 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.

benefits. Total HRA costs for 2015 are expected to be approximately $1.8 million, representing an increase of $70,000 over 2014 costs.

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 2015 cost for miscellaneous employee benefits?

A. PGE forecasts 2015 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: $463,734 – 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: $230,850 – 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 2015 cost for benefits administration?

A. PGE forecasts 2015 benefits administration costs to be approximately $588,000. This represents an increase of 2.6% relative to 2014 and is attributable to base escalation as discussed in PGE Exhibit 300.

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. 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.

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.

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, 2013. Second, for Financial Accounting Standards (FAS) purposes, PGE's pension plan was 85% funded as of December 31, 2013. This compares to 74% as of

[8] The Pension Protection Act of 2006 (Pub. L. 109–280), 120 Stat. 780.

December 31, 2012. The rise in funded status can be attributed to an overall improvement in the market for 2013 coupled with PGE's market performance relative to other plans.

Q. How has PGE's pension asset performed relative to the market?

A. PGE's pension plan assets have consistently outperformed similar sized pension plans for the last five years, being in the top decile of funds over the five years ending September 30, 2013. Additionally, from 2000 through 2011, PGE's pension plan performance outpaced the average pension returns of the nation's largest companies (companies listed in the 2012 *Fortune* 1000) by an average of 1.2% annually.

Q. Have PGE's customers benefitted from PGE's pension plan performance?

A. Yes. Better plan management and performance reduces PGE's FAS 87 expense, which directly benefits customers in two specific ways. First, during years when there is a rate case, our FAS 87 expense forecast is lower than it otherwise would be as a result of our effective plan management. Second, in the years between rate cases, if FAS 87 expense is lower than what is in rates, PGE is able to increase investments elsewhere, benefiting customers without an associated increase in rates.

Q. What are PGE's projections for expense, cash contributions, and the funded status of the pension plan for the next 5 years?

A. PGE, with the assistance of its third party actuary Towers Watson, estimated PGE's pension expense and cash contributions for the next 5 years. Confidential PGE Exhibit 602C contains estimates as of December 13, 2013.

Q. Please 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 that grow PGE's prepaid pension asset. Section A, below, describes them in more detail and how they affect PGE.

A. Pension Funding Requirements

1. Pension Expense (FAS 87)

Q. Please describe the components of FAS 87 expense used to calculate pension expense.

A. There are five components used to calculate pension expense. These components are service cost, interest cost, expected return on assets, amortization of prior service costs/credits, and amortization of actuarial gains/losses.

- Service cost − The service cost is a calculation of the annual pension benefits accrued by active participants in the pension plan. Put simply, it is the amount current participants earn for the current year.
- Interest cost − Added to service cost is the interest cost for the year. Interest cost reflects the increase in the Pension Benefit Obligation (PBO) for the passage of time (i.e., time value of money), using the current discount rate.
- Expected return on assets − From these amounts, the estimated return on assets (calculated by multiplying the expected market return by the Market Related Value of Assets), is subtracted.
- Amortization of prior period service costs − Then the amortization of prior service costs, which represents any changes to the plan, is added. For PGE, this small amount will be fully amortized by 2015.
- Amortization of actuarial gains/losses − Finally, the amortization of any actuarial gains or losses is included. This calculation determines the difference between what was

previously forecasted to happen by the actuary and what actually happened, then spreads the gain or loss over the remaining service life of the plan.

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 Consulting. 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?

A. PGE uses a discount rate of 4.76%, 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. Who calculates the annual FAS 87 expense?

A. Consistent with standard accounting practices, PGE uses a professional third party actuary to determine our pension liabilities and expenses. The Financial Accounting Standards Board (FASB) requires that pension expense be actuarially determined and that it reflect the service component of expense over the period during which employees render services. These third party actuaries have years of education and experience specific to pension accounting, making them uniquely suited to the task of forecasting and determining PGE's pension liabilities and expense.

Q. What is the purpose of FAS 87?

A. The intended purpose of FAS 87 is to smooth a company's pension expense over the life of its pension plan. This smoothing can be seen in the amortization components of pension expense.

Q. What is PGE's forecasted 2015 pension expense?

A. PGE's 2015 pension expense is forecasted to be $25.2 million (or approximately $15.2 million after capitalization). This represents a decrease of approximately $260,000 from PGE's budgeted 2014 pension expense.

2. Prepaid Pension Asset & Cash Contributions (Pension Protection Act)

Q. Please summarize the requirements of the Pension Protection Act (PPA).

A. Signed into law in 2006 and enacted in 2008, the PPA creates and requires pension plan sponsors to meet minimum funding targets for private pension plans.

Q. Please explain what PGE's prepaid pension asset is comprised of.

A. PGE's prepaid pension asset is comprised of contributions in excess of FAS 87 expense. The two main determinants of the prepaid asset amount are direct cash contributions and the amount of FAS 87 expense incurred.

Q. How has the PPA affected the prepaid pension asset?

A. First, the PPA's amortization schedule for cash contributions is considerably shorter in length than the amortization schedule under FAS 87, significantly increased the difference between the build-up of the prepaid asset and its reduction through FAS 87 expense. Second, the PPA increased funding requirements, requiring large cash contributions to the plan in excess of FAS 87 expense. This federally required increase in cash contributions has contributed substantially to the size of the prepaid pension asset and can affect our overall financing ability. Absent regulatory treatment of these costs, PGE's opportunity to earn its allowed Return on Equity will be diminished.

Q. How much cash has PGE contributed to its prepaid pension asset 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 $55 million over the next five years.

Q. What is the relationship between the prepaid asset and pension expense?

A. The prepaid asset is amortized through PGE's pension expense. That is, as PGE incurs FAS 87 pension expense, the prepaid asset is reduced by that amount, offset by cash contributions, if any. The prepaid asset effectively amounts to a difference in timing between the two: pension expense and cash contributions.

Q. If FAS 87 expense is reduced every time a cash contribution is made to the prepaid asset, how does the prepaid asset diminish?

A. While cash contributions reduce FAS 87 expense by increasing the asset base and therefore the expected return on assets component of FAS 87 expense, PGE continues to incur service cost, interest cost, amortization of prior service cost, and amortization of actuarial gain/loss. These remaining FAS 87 expense components continue to reduce the prepaid asset and as the plan gets closer to being fully funded, the cash contributions taper off, while FAS 87 expense continues to be incurred.

Q. Will this prepaid asset eventually reach a zero balance?

A. Yes. While cash contributions are only necessary to fund the plan, FAS 87 expense continues through the life of the plan, reducing the prepaid pension asset balance to zero.

B. Pension Cost Recovery

Q. What is PGE requesting regarding pension cost recovery?

A. We request the recovery of PGE's 2015 pension expense and a return on PGE's average 2015 prepaid pension asset, net of deferred taxes, through its inclusion in rate base. Together, these items represent $18.5 million in pension related costs that PGE is seeking recovery of for 2015.

Q. What amount related to the prepaid pension asset has PGE included in rate base for 2015?

A. The net amount related to the prepaid pension asset that is included in PGE's rate base for 2015 is approximately $22.6 million.

Q. Under this treatment are there any offsetting benefits that customers receive?

A. Yes. PGE has included the accumulated deferred taxes associated with the prepaid pension asset in rate base for 2015. The amount included in PGE's 2015 rate base is reduced by approximately $26.4 million from the inclusion of this deferred tax offset.

Q. What is the appropriate regulatory treatment of this deferred tax liability?

A. Both the costs and benefits associated with the prepaid pension asset should either be included in rate base or removed from rate base. Any pension related deferred tax liability is directly associated with a utility having a prepaid pension asset. Therefore, it would be inappropriate regulatory treatment for customers to benefit from this deferred tax offset to rate base when the prepaid pension asset that has created this deferred tax liability is excluded from rate base.

Q. What is the status of the generic pension proceeding (Docket No. UM 1633) and how will it inform the type of recovery PGE will receive in this general rate case proceeding?

A. Docket No. UM 1633 is an on-going investigation into the treatment of pension costs in utility rates. This docket is a generic investigation involving all investor owned utilities operating in Oregon. The purpose of this docket is to investigate and address the current rate making treatment of pension costs. What this docket will ultimately inform is how the Commission recommends treating the prepaid pension asset and the associated deferred tax liability. A commission order for UM 1633 is targeted for the third quarter of 2014 and may affect how pension-related costs are treated in this proceeding.

Q. If PGE were granted recovery of only pension expense, wouldn't PGE's pension plan be made whole over time?

A. No. 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. It can also adversely affect PGE's ability to attract necessary capital.

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. Mr. Jaramillo, please summarize your qualifications.

A. I received a Bachelor of Arts degree in economics from Northwest Nazarene University and am completing coursework toward a Masters of Business Administration at the University of California, Los Angeles. 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, becoming the Director of Compensation and Benefits in 2013.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
601	2010-2015 FTEs
602C	Five Year Pension Forecast

DIVISION	CLASS	DEPT	REG/ TEMP	Officer	2010 FTE (PGE Share)	2011 FTE (PGE Share)	2012 FTE (PGE Share)	2013 FTE (PGE Share) - September	2014 BUDGET FTE (PGE Share)	2015 GRC FTE (PGE Share)	FTE Delta 2015-2014	Annual % Delta 2014-2015
A&G - INFORMATION TECHNOLOGY Total					266.0	251.2	249.8	241.0	252.1	255.1	3.0	1.19%
ADMINISTRATIVE AND GENERAL Total					374.5	378.7	361.1	358.8	363.5	366.0	2.5	0.69%
CUSTOMER ACCOUNTS Total					478.2	425.7	406.9	398.5	425.7	425.5	(0.2)	-0.05%
CUSTOMER SERVICE Total					72.4	78.5	85.7	83.6	92.1	99.9	7.8	8.48%
GENERATING - BEAVER Total					52.9	53.7	55.1	49.8	53.1	53.1	-	0.00%
GENERATING - BIGLOW Total					6.0	6.5	7.6	8.0	8.0	8.0	-	0.00%
GENERATING - BOARDMAN Total					71.6	71.2	72.9	71.9	94.6	94.6	-	0.00%
GENERATING - COYOTE Total					15.0	16.5	16.8	16.4	14.9	15.4	0.5	3.36%
GENERATING - OTHER Total					265.0	272.1	280.0	290.2	305.6	314.9	9.3	3.04%
GENERATING - PORT WESTWARD Total					20.4	20.9	20.9	21.5	25.4	25.4	-	0.00%
GENERATING - TROJAN Total					11.5	11.5	11.7	11.3	11.5	11.5	-	0.00%
GENERATING - TUCANNON Total					-	-	-	-	-	5.0	5.0	#DIV/0!
TRANSMISSION & DISTRIBUTION Total					958.6	957.0	927.9	917.7	966.5	962.6	(3.9)	-0.40%
Grand Total					2,592.0	2,543.5	2,496.4	2,468.7	2,612.9	2,636.9	24.0	0.92%

Adjusted Totals by Division

IT	266.0	251.2	249.8	241.0	252.1	255.1	3.0	1.19%
Unfilled Position Adjustment					(7.4)	(7.1)	0.3	
MyTime Adjustment								
Adjusted IT Totals	266.0	251.2	249.8	241.0	244.7	248.1	3.3	1.36%
A&G	374.5	378.7	361.1	358.8	363.5	366.0	2.5	0.69%
Unfilled Position Adjustment					(10.5)	(10.1)	0.4	
MyTime Adjustment								
Escalation Adjustment								
Adjusted A&G Totals	374.5	378.7	361.1	358.8	353.0	355.9	2.9	0.82%
Adjusted A&G/IT Totals	640.4	629.9	610.8	599.8	597.7	603.9	6.2	1.04%
Customer Accounts	478.2	425.7	406.9	398.5	425.7	425.5	(0.2)	-0.05%
Unfilled Position Adjustment					(11.7)	(11.1)	0.6	
MyTime Adjustment								
Incremental FTEs offset by Other Revenue						(1.0)	(1.0)	
Adjusted Customer Accounts Totals	478.2	425.7	406.9	398.5	414.1	413.4	(0.6)	-0.15%
Customer Service	72.4	78.5	85.7	83.6	92.1	99.9	7.8	8.48%
Incremental FTEs offset by Other Revenue						(7.0)	(7.0)	
N/A								
Adjusted Customer Service Totals	72.4	78.5	85.7	83.6	92.1	92.9	0.8	0.88%
Adjusted Customer Accounting/Service Total	550.6	504.2	492.6	482.1	506.1	506.3	0.2	0.03%
T&D	958.6	957.0	927.9	917.7	966.5	962.6	(3.9)	-0.40%
Unfilled Position Adjustment					(16.3)	(15.9)	0.4	
MyTime Adjustment								
Adjusted T&D Totals	958.6	957.0	927.9	917.7	950.2	946.7	(3.4)	-0.36%
Generation	442.4	452.4	465.1	469.1	513.0	527.8	14.8	2.88%
Unfilled Position Adjustment					(11.2)	(10.8)	0.4	
MyTime Adjustment								
Incremental FTEs in CWIP					-	(7.2)	(7.2)	
Adjusted Generation Total	442.4	452.4	465.1	469.1	501.7	509.8	8.0	1.60%
Unadjusted Total	2,592.0	2,543.5	2,496.4	2,468.7	2,612.9	2,636.9	24.0	
Unfilled Position Adjustment	-	-	-	-	(57.1)	(54.9)	2.2	
MyTime Adjustment	-	-	-	-	-	-	-	
Incremental FTEs not in Rates	-	-	-	-	-	(15.2)	(15.2)	
Escalation Adjustment	-	-	-	-	-	-	-	
Adjusted Grand Total	2,592.0	2,543.5	2,496.4	2,468.7	2,555.8	2,566.8	11.0	0.43%

Exhibit 602C

Confidential

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 283

Corporate Support

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Jim Lobdell
Cam Henderson
Alex Tooman

February 13, 2014

Table of Contents

I. Introduction

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

A. My name is Jim Lobdell. I am the Senior Vice President, Finance, Chief Financial Officer, and Treasurer at PGE. My qualifications appear at the end of PGE Exhibit 100.

My name is Cam Henderson. I am the Vice President of Information Technology (IT) and Chief Information Officer at PGE. My qualifications appear in Section VI of this testimony.

My name is Alex Tooman. I am a Project Manager for PGE. My qualifications appear at the end of PGE Exhibit 300.

Q. What is the purpose of your testimony?

A. We explain PGE's request for $154.9 million in administrative and general (A&G) costs in 2015 and compare it to the 2014 budget of $147.7 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 701 provides a list of A&G functions plus a summary of costs and full time equivalent (FTE) employees for 2010 (actuals) through 2015 (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	2014 Budget	2015 Forecast	Delta* 2015-2014
Facilities/General Plant Maintenance	$ 4.9	$ 5.1	$ 0.3
Accounting/Finance/Tax	9.5	9.9	0.4
HR/Employee Support	8.0	8.2	(0.2)
Insurance, Injuries and Damages, etc.	11.9	12.9	0.9
Legal	6.9	7.1	0.2
Regulatory Affairs/Compliance	3.1	3.2	0.1
Corporate Governance	3.8	3.9	0.2
Business Support Services	2.9	3.0	0.1
Environmental Programs	2.5	5.6	3.1
Corporate R&D	1.5	1.5	0.0
Contract Services/Purchasing	1.5	1.6	0.1
Security and Business Continuity	1.9	2.2	0.2
Corp Communications/Public Affairs	1.9	1.9	0.0
Load Research	0.1	0.0	(0.1)
Hydro Licensing	0.2	0.3	0.1
Performance Management	1.6	1.6	0.1
Governmental Affairs	1.0	1.0	0.0
Total for Major Functional Areas*	$ 63.4	$ 68.9	$ 5.5
IT: Direct and Allocated	$ 12.2	$ 12.7	$ 0.5
Labor Cost Adjustment	(2.2)	(2.2)	-
Membership Costs	3.3	3.6	0.3
Incentive Plans (net of capital allocations)	8.5	8.9	0.1
Regulatory Fees	6.3	7.0	0.7
General Plant Maintenance	2.5	2.5	0.0
Net PTO	5.3	5.5	0.2
Benefits (net of capital allocations)	51.9	53.0	1.1
Corporate Allocations	(6.2)	(6.3)	(0.1)
Revolver Fees, Margin Net Int., Broker Fees	2.5	1.3	(1.2)
Total Other A&G Costs*	$ 84.4	$ 86.0	$ 1.7
Total A&G*	$ 147.7	$ 154.9	$ 7.2

* May not sum due to rounding.

Q. Why are you comparing the 2015 test year costs to the 2014 budget?

A. We do so because the 2014 budget approximates final UE 262 costs that are currently in PGE's retail rates, as approved by Commission Order No. 13-459. As noted in PGE Exhibit 300, because we are holding PGE's overall 2014 budget flat to the final stipulated costs from UE 262, comparing the 2015 forecast to the 2014 budget reflects the most relevant cost increases.

Q. How would you characterize the forecasted increase in A&G costs from 2014 to 2015?

A. Most of the A&G cost increase from 2014 to 2015 can be attributed to three primary drivers: benefits, environmental services, and insurance. Benefits, as discussed in PGE Exhibit 600, are largely driven by health care costs. Environmental Services encompasses the costs associated with regulatory reporting and compliance requirements (at federal, regional, state, and local levels) related to environmental issues. Insurance costs continue to be subject to the same trends that we identified in PGE's 2014 general rate case (UE 262) and describe in more detail below. 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. Beyond these specific items, the increase from 2014 to 2015 is mostly a function of cost escalation due to inflation.[1]

Q. Does your forecast include any cost reductions related to efficiencies?

A. Yes. As stated in PGE Exhibit 100, PGE presented $15.6 million of cost savings and avoidance related to efficiency in its 2014 rate case filing (Docket No. UE 262). These savings continue to be reflected in our 2014 budget in addition to $6.1 million further savings that we identified for 2014. For 2015, we include these savings plus an additional $1.7 million that have been identified in 2015 for a total of $23.4 million of savings. PGE Exhibit 707 provides additional detail on the components of these savings and the operating areas in which they were attained.

Q. How is your testimony organized?

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[1] Absent the increases for benefits, environmental services, insurance, and OPUC fees (which are a revenue sensitive cost included in A&G), PGE's A&G costs increased by only 0.96% from 2014 to 2015.

A. In the next section, we describe the major cost drivers by A&G function. We then discuss PGE's Information Technology efforts on a corporate basis. Next, we provide detail regarding increases in other A&G costs. We then summarize our request in this filing. We conclude with Mr. Henderson's qualifications.

II. Primary A&G Cost Increases

A. Benefits

Q. By how much do you forecast benefit costs to increase from 2014 to 2015?

A. The increase in net benefit costs from 2014 to 2015 is approximately $1.1 million and includes such items as health and dental plans, PGE's 401(k) and pension plans, workers' compensation, and employee life and disability insurance.

Q. What accounts for this increase?

A. The primary drivers are increasing premiums for health care and dental insurance. PGE Exhibit 600 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 600 explains the gross corporate forecast for these costs.

Q. How does PGE mitigate cost increases for employee benefits?

A. As discussed in PGE Exhibit 600, major ways PGE works to keep benefit costs down are by sponsoring programs that encourage a healthy workforce, modifying benefits plan structures to track market practice, and negotiating favorable contract terms with vendors. Our goal is to maintain a fair and competitive benefits package that will help us attract and retain a quality workforce, while still controlling costs.

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 confidential Exhibit 702C and Exhibit 703. In general, the insurance coverage maintained by PGE falls into two broad categories: property and liability & casualty. We discuss these below and also address retained losses.

Q. What is PGE's forecast of insurance premiums for 2015?

A. As shown in Table 2 below, insurance premium costs are expected to be approximately $10.9 million in 2015, increasing from $10.0 million in 2014. Roughly half of the increase in property premiums can be attributed to the overall increase in the value of the property insured within the program; with the balance attributable to increases in the rate charged by the insurers. Within the liability & casualty program, the majority of the premium increase is attributable to general liability insurance coverage where insurers are seeking rate increases from utility sector accounts as a means to recover from adverse liability losses that have plagued the utility sector in recent years.

Table 2
Insurance Premiums ($ million)*

Type of Policy	2014	2015	Annual Average % Increase
Property	$4.90	$5.45	11.2%
Liability & Casualty	$5.14	$5.45	5.9%
Total	**$10.04**	**$10.90**	**8.5%**

*Amounts Exclude Port Westward 2 and Tucannon River Wind Farm

Q. What is PGE's forecast of expenditures for retained losses from 2014 to 2015?

A. As shown in Table 3, PGE's forecast of expenditures for retained losses increases $0.04 million from 2014 to 2015. We discuss retained losses in more detail below.

Table 3
Retained Losses ($ million)

Type of Loss	2014	2015	Annual Average % Increase
Workers' Compensation	$1.86	$1.90	2.2%
Auto & General Liability	$1.68	$1.68	0.0%
Total	**$3.54**	**$3.58**	**1.1%**

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 could otherwise result in an adverse material effect on PGE's financial stability and potentially negatively impact 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. This is due to the fact that most insurance companies manage their exposure to risk by limiting the amount of insurance capacity that they provide to any one company. To acquire adequate coverage limits, diversify exposure (so as to not excessively rely on any one carrier) and reduce risk, an insurance structure is assembled whereby the primary insurer provides specific coverage terms and capacity limits, but 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 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. This practice is common in the insurance industry and reduces overall risk.

Q. How does PGE forecast its insurance premium costs?

A. We base the estimates on the most recent data for PGE's 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. Sluggish US economic growth, high catastrophe losses, and a low interest rate environment have made it difficult for insurers to produce investment income with their collected premiums. This continuing trend is causing overall rates to show signs of hardening.[2] However, there are other trends related to specific lines of insurance coverage, such as property, general liability and directors & officers (D&O) insurance.

Q. Please discuss the trends in the area of property insurance.

A. The leading driver of change in the global property insurance markets continues to be natural catastrophe losses around the world and PGE expects this pattern to continue in to 2015 as insurers struggle to rebuild their surplus.[3] The global property market continues to see most insurers seeking moderate rate increases for accounts in non-catastrophe exposed areas (e.g., flood, earthquake, named windstorm, etc.). Although PGE is exposed to flood and earthquake risks, for the most part PGE is not exposed to named windstorm risks.

Q. What are the trends for general liability insurance?

A. Recent rate increases experienced within the utility sector are expected to continue into 2015. These increases have been driven by two factors: (1) large industry loss events such as the San Bruno (PG&E) gas pipeline explosion and western wildfires; and (2) increased claims relating to aging infrastructure, weather events, and legacy issues such as pollution. Because of this adverse loss experience, utilities can expect underwriters will be seeking renewal premium increases in the low double-digits as a means of stabilizing their book of business within their general liability portfolio. Workers' compensation coverage is expected to increase through 2015 due to a deteriorating workers' compensation insurance

[2] "Hardening" refers to an insurance market that is restricting capacity (capacity is defined as the largest amount of insurance or reinsurance available from the market in general), which in turn drives up rates.
[3] Twelve of the last sixteen most expensive natural catastrophes have occurred over the past decade, with 2012 likely being the third costliest year ever for insured natural catastrophe losses. Also, the effects of super-storm Sandy in 2012 (estimated cost of $65 billion – see NOAA: http://www.ncdc.noaa.gov/billions/events), recent flooding in Germany, and recent tornado activity in the US are having adverse effects on the property insurance markets.

market driven by a persistent rise in medical costs that are increasing faster than the rate of inflation.

Q. What are the trends for D&O liability insurance?

A. Merger activity and associated "merger objection" filings continue to be a leading cause of D&O claims and a key issue for utility D&O underwriters. We expect this trend to produce D&O premium increases in the mid-single digits in 2015.

Q. Are there other significant trends related to insurance coverage?

A. Yes. Data breaches have continued to increase across the U.S with some 447 data breaches and over 17 million records exposed in 2012 (government and business organizations accounting for the majority of records exposed by data breaches). In 2009, PGE added network security & privacy liability coverage to its insurance portfolio to help mitigate the financial consequences of a cyber-attack or data breach. The market for network security & privacy liability coverage remains stable with ample capacity and moderate rate increases depending on the industry.

3. Property Insurance

Q. You noted above that the general upward trend in insurance rates is due to increased losses. Does this trend explain the increase in PGE's property insurance premiums?

A. Yes, but only partially. As previously mentioned; the rates charged by property insurers are influenced by natural catastrophe losses experienced in the marketplace as well an individual insured's loss experience. The increase in PGE's property insurance premiums is driven by two factors: (1) increases in the total value of the insured property; and (2) increases in the rate charged by the property insurer which is applied to PGE's total insured property value to determine the premium charged. The cumulative effect of these two factors accounts for the 11.2% overall increase in property insurance premiums from 2014 to 2015. Of this increase, roughly half can be attributed to the overall increase in the value of the property insured within the program with the balance attributable to increases in the rate charged by the Insurers.

Q. Is there anything else that will cause PGE's property insurance premiums to increase in 2015?

A. Yes. Port Westward 2 and Tucannon River Wind Farm (Tucannon) will increase property insurance premiums in 2015. Based on the projects' total insured values and the forecasted rate increases, we expect Port Westward 2 and Tucannon to increase PGE's 2015 property premium by approximately $0.62 million in addition to the 2015 property premium shown in Table 2 above. PGE Exhibit 400 discusses Port Westward 2 and Tucannon in more detail.

4. Liability

Q. What types of coverage are included in PGE's liability & casualty insurance program?

A. Table 4 below displays the components of PGE's liability & casualty insurance program

Table 4
Liability & Casualty Program Components

- General Liability
- Directors and Officers (D&O) Liability
- Fiduciary Liability
- Workers Compensation
- Nuclear Liability
- Network Security & Privacy Liability
- Aviation Hull & Liability
- Western Interconnected Electric Systems (WIES)
- Surety Bonds

PGE Exhibit 702C describes each policy's purpose in more detail.

Q. Please describe the premium increases in PGE's general 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. As previously noted, increases in general liability coverage are 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 claims creating additional upward rate pressure.

Q. Why is D&O insurance coverage important?

A. D&O liability insurance is important for the following reasons:

- It protects customers and shareholders from the consequences of financial distress of potential claims;
- The limits purchased are consistent with standard practice of the utility industry and reduce overall risk to both customers and shareholders.
- Maintaining the appropriate limit and type of D&O insurance is necessary to attract and retain qualified and competent directors and officers; and,
- It shields PGE's directors and officers against normal, but sometimes significant, risks associated with managing the business.

Q. Why does PGE purchase workers' compensation insurance?

A. The State of Oregon requires PGE to maintain coverage to protect itself from catastrophic losses to employees arising out of and in the course of employment.

5. Retained Losses

Q. What are retained losses?

A. Retained losses are the portion of any claim falling within PGE's self-insurance retentions for its auto liability, general liability, and workers' compensation exposures that are frequent and predictable. Simply put, retained losses are the amounts borne by PGE before any insurance recoveries.

Q. What method does PGE use to forecast workers' compensation, auto liability, and general liability losses?

A. Annually, 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 independent actuarial firm assembles and analyzes data (from over the past 17 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 2.2% increase in workers' compensation projected loss is a function of cost escalation due to inflation.

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 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 injured employees who cannot return to work.

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 1.1% between 2014 and 2015.

C. Environmental Services

Q. By how much do you expect environmental service costs to increase from 2014 to 2015?

A. We forecast that Environmental Service (ES) costs, as charged to A&G, will increase from approximately $2.5 million in 2014 to $5.6 million in 2015. This is primarily related to the remediation of portions of the Downtown Reach area of the Willamette River.

Q. Please describe the environmental activities associated with the Downtown Reach.

A. The Downtown Reach area of the Willamette runs from River Mile 11.8 to 16.0. In 2015, PGE expects to be involved in remediation activities in the Downtown Reach at River Miles 13.1 and 13.5 in compliance with Oregon Department of Environmental Quality (ODEQ) and U.S. Environmental Protection Agency (EPA) regulation.

In 2012, PGE completed a Remedial Investigation (RI) under an Administrative Order of Consent by the ODEQ and we are currently in the process of drafting a Feasibility Study for storm water discharge areas partially originating from PGE's former Hawthorne Shop (at River Mile 13.1) and previously owned Station L (now OMSI – at River Mile 13.5). In 2013, PGE also completed the Source Control Evaluation for upland sources, including the Hawthorne Building. Based on data collected and characterized in these two studies, PGE anticipates that ODEQ will require remediation of sediment contamination in the river at miles 13.1 and 13.5. We anticipate the draft Feasibility Study will be completed in 2014, and in 2015 we expect remedial action to begin with the in-water work period.[4]

Q. What are the expected costs of the remediation projects in the Downtown Reach?

[4] The in-water work period is the time available for working in the water due to fish passage being at a low point in the river.

A. PGE estimates the remediation cost at River Miles 13.1 and 13.5 to be approximately $3.1 million. PGE Exhibit 704 provides a map of the remediation area.

Q. Does PGE expect reimbursement of those expenses?

A. PGE continues to receive 45% of undisputed costs associated with the defense and investigation from two insurers regarding the Portland Harbor and Downtown Reach areas, but we have not reached agreement with insurers regarding expected remediation for River Miles 13.1 and 13.5 in the Downtown Reach area. As part of PGE's continued involvement in the Portland Harbor Superfund site and Downtown Reach, and in an attempt to recover legal, investigation and clean-up costs, PGE notified all identified domestic and London insurers that remain solvent, of the environmental claim. PGE's efforts to pursue similar defense cost-sharing agreements with other insurers continues.

Q. Has PGE included all of these costs in the test year forecast?

A. Yes. The 2015 test year forecast, as filed, includes the $3.1 million increase. We propose, however, to mitigate the cost increases associated with environmental remediation efforts along the Willamette River (including the Downtown Reach and Portland Harbor) by reclassifying them to a regulatory asset, which we would then amortize over 20 years. If the Commission approves this accounting treatment, we request that they authorize it as part of the final order in this general rate proceeding. More details regarding the regulatory asset are provided in PGE Exhibit 300. If the proposed accounting treatment is approved, test year environmental costs would decrease by approximately $2.9 million.

Q. Will PGE bid the remediation work to outside experts through a request for proposals?

A. Yes. PGE will bid the remediation project to outside contractors and may bid the verification and report writing for consultants as well. These outside experts will administer and implement the remediation effort in phases. We list below possible phases for this remediation effort:

- Permitting and Design Labor: project scoping/planning and review, communications with client and ODEQ, finalization of the Erosion and Sediment Control Plan greenway permit, coordination of compliance around bird migration and mitigation plans, permitting requirements, coordination with the State Historical Preservation Office, permit application/design revising, if needed, and general project administration.
- Contractor Procurement: project management, bid review and contract implementation, review health and safety for subcontractors, review of bids, training requirements and qualifications for contractors, review of submittals, scheduling, design and approach, plus work order preparations.
- Oversight and Remedy Implementation: project management, review of compliance documentation, project coordination, sample collection confirmation, water quality monitoring, waste management, oversight during construction, field support as needed, project invoicing and correspondence oversight.
- Draft Remedial Action Report (RAP): Review of draft RAP document, compliance document preparation, post remedy risk assessment evaluation, reporting, logging, sample sheets, general work flow schedule, reporting and preparation, plus project administration and document formatting.

Q. What are the remedial activities expected to involve?

A. The final Feasibility Study is expected to address the installation of an isolation cap for River Mile areas 13.1 and 13.5, and will consist of the following:

- Address the designated objectives for sediment remediation.
- Reduce mobility of the "chemicals of concern" in the underlying sediment.
- Protect human health and ecological receptors through implementing appropriate engineering and institutional controls (e.g., engineering and installing the isolation cap and limiting access to the site by placing an easement on the bottom of the river).
- Implement effective treatment of surface and subsurface areas of contamination.
- Substantially reduce the "site-specific surface weighted average concentration" as well as reliably prevent the risk to future human and environmental health.

Q. Does this comprise all of the environmental costs charged to PGE?

A. No. The ES consists of two principal activities:

- Costs associated with investigation and reporting are incurred in A&G, primarily FERC accounts 920 (Administrative and General Salaries) and 923 (Outside Services Employed).
- 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, primarily FERC account 537, Hydraulic Expense.

Table 5 below, summarizes PGE's total ES costs for 2014 and 2015.

Table 5
Environmental Services by Operating Area
($ million)

Operating Area	**2014 Budget**	**2015 Budget**	**Delta 2015-2014**
A&G	$2.48	$5.56	$3.08
Production O&M	$3.71	$3.75	$0.04
Total ES	$6.19	$9.31	$3.12

III. Information Technology

A. Overview

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[5] to increase by the 2015 test year?

A. From 2014 to 2015, we forecast total IT costs to increase from $56.5 million to $66.9 million.[6] Because these costs relate to all areas of PGE's operations, they are charged or allocated to appropriate operating 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. Please explain why IT O&M costs are expected to increase approximately $10.4 million from 2014 to 2015?

A. The $10.4 million increase is due to two factors:

- The primary factor is the IT deferral mechanism, which was created through a stipulation in PGE's previous general rate case (UE 262).
- The secondary factor is labor loadings on allocated IT O&M, which increase as labor-related costs increase (i.e., employee benefits).

[5] Unless specifically indicated as capital costs, all costs in this testimony refer to O&M costs.
[6] The IT amounts listed in Table 1 relate only to the costs charged and allocated to A&G. The total IT amounts represent the costs charged and allocated to all operating areas.

Removing the effects of these factors, PGE's incurred IT O&M costs are expected to be flat from 2014 to 2015, with a small increase of approximately $300,000. This small increase results from the net effect of several factors including:

- A $2.9 million reduction in development O&M costs described in Section B, below.
- A $1.9 million increase for software and hardware maintenance agreements. $1.0 million of this relates to licensing and maintenance agreements for the 2020 Vision projects that will be in service in late 2014 and in 2015, as described in Section D, below.
- General labor and non-labor cost escalation.

B. UE 262, IT Deferral Mechanism

Q. Please describe the IT Deferral Mechanism from your last general rate case, UE 262?

A. The issue arose in UE 262 because of the distinction noted between the two primary O&M activities performed by PGE's IT department:

- Activities related to "developing" systems; and
- Activities related to "running" existing systems.

As part of the UE 262 settlement process, parties stipulated that for 2014, O&M costs associated with developing IT systems should be capitalized and subject to a five-year amortization (although all parties did not necessarily agree with this position). The Stipulation, subsequently adopted by Commission Order No. 13-459, removed approximately $8.7 million of IT development O&M expense from PGE's 2014 revenue requirement and replaced it with:

- A regulatory asset of approximately $7.8 million to be included in 2014 rate base; and

- Amortization expense of approximately $1.7 million representing one-fifth of the capitalized amount.

Q. What is the impact of this mechanism in PGE's 2015 revenue requirement?

A. PGE's 2015 revenue requirement will reflect a regulatory asset from 2014 with approximately $6.9 million of average rate base and amortization expense of $1.7 million.

Q. Besides the effects noted above, does PGE plan to continue applying the IT Deferral Mechanism for costs budgeted in 2015?

A. No. We believe that the IT Deferral Mechanism is not appropriate because PGE records its costs (i.e., determines capitalization versus expense) in accordance with Generally Accepted Accounting Principles (GAAP), which are codified by the Financial Accounting Standards Board (FASB). In addition, PGE is audited annually by Deloitte and Touche, LLP, which reviews the accuracy of our accounting entries and our compliance with GAAP. PGE Exhibit 705 provides more information on the criteria specific to capitalizing IT Project costs under GAAP.

Q. What is PGE's current proposal for the IT Deferral Mechanism?

A. PGE proposes to amortize the remainder of the 2014 regulatory asset in accordance with the stipulation and Commission Order No. 13-459. We do not, however, propose to defer any IT development O&M costs for 2015 because they are correctly classified as expense.

Q. How does the decision to not defer IT development O&M costs for 2015 affect the 2015 forecast relative to the 2014 budget?

A. It gives the appearance that IT costs increase by approximately $8.5 million rather than increase by approximately $0.3 million. This is unavoidable because the mechanism reduced O&M costs in 2014 but we are not applying the mechanism to 2015 costs. The 2015 forecast also includes the one-fifth amortization of the regulatory asset.

Q. Do customers derive any benefit from the IT Deferral Mechanism?

A. No. If PGE were to continue to use the IT Deferral Mechanism in this and subsequent general rate cases, customers would only pay more for the same costs. This is because the regulatory asset would grow as PGE pursues general rate cases and the additional rate base would generate the "return on" as well as "return of" component for customers to absorb. Over time then, customers would not only pay for the O&M development costs but also the "return on" rate base that occurs only because of the deferral mechanism.

Q. Did parties propose any similar mechanisms in prior rate cases?

A. No. In UE 115, UE 180, UE 197, and UE 215, PGE separately identified its IT costs and discussed them in testimony. No party in any of those proceedings expressed concern about PGE's accounting for IT capital versus O&M.

Q. Was any aspect of the UE 262 adjustment related to disallowing costs due to imprudence?

A. No. The adjustment was solely related to the reclassification of IT development O&M costs.

Q. Are these costs unique because they represent "one-time" costs?

A. No. System development is a recurring and on-going aspect of the IT environment that will not cease. The accelerating life cycle of software systems and the on-going need for new or upgraded applications means that IT development is continual. In fact, system development entails both the enhancement of existing systems as well as the evaluation, establishment of requirements, and actual implementation of new systems.

Q. How much IT development O&M does PGE incur annually?

A. Table 6, below, provides a summary of PGE's IT development O&M for 2008 to 2013 actuals plus the 2014 budget and 2015 forecast amounts. Although the amounts vary from year to year depending on the number and scope of projects being implemented, the overall activity is significant every year as well as recurring.

Table 6
IT Development O&M by Year
($ million)

Development O&M	2008	2009	2010	2011	2012	2013	2014	2015
Enhance Existing Systems	0.9	3.4	2.8	3.3	3.7	2.2	2.1	1.5
Develop new systems	1.6	2.1	2.9	6.5	4.0	3.6	5.0	2.7
Total Development O&M*	2.4	5.5	5.7	9.8	7.6	5.8	7.1	4.1

* May not sum due to rounding.

Q. Why has the amount of development O&M increased and then decreased over the listed time frame?

A. As noted above, the amounts will vary from year to year depending on the number and scope of projects being implemented. The trend noted in Table 6 relates primarily to the large, multi-year IT programs that we described in PGE Exhibit 600 from our UE 215 general rate case. Therein, we noted the following:

- In 2009, PGE initiated the 2020 Vision program, and
- In 2010 we began the Cyber Security Roadmap project.

As these IT initiatives ramped up over subsequent years, we incurred increasing costs associated with both capital and O&M development. As the projects are being completed in 2015, the level of development activity correspondingly declines.

Q. Please summarize your position regarding the IT deferral.

A. We request that the Commission not authorize any additional deferred accounting treatment associated with PGE's IT development O&M costs. We believe the accounting for these costs should follow GAAP and not be modified. We would also note that PGE does not track its IT O&M costs by the categories required by the mechanism. As noted above, we appropriately record the costs as either capital or O&M. Further separating the O&M costs between developing systems and running systems, requires a subjective review of considerable accounting detail based on the Accounting Work Order, which is a field that identifies specific projects or activities. This purely manual activity highlights the artificial nature of forcing this unnecessary distinction between IT O&M costs.

C. Other IT O&M Costs

Q. In Section III. A., you stated that IT's total O&M costs increased by approximately $10.4 million from 2014 budget to the 2015 forecast and that these are attributable to the IT Deferral Mechanism and labor loadings. Please explain the basis of the labor loadings.

A. Table 7 below, summarizes the categories of total IT costs and identifies the components that account for the forecasted $10.4 million increase, including loadings.

Table 7
Total IT Costs ($ million)

Category	2014 Budget	2015 Forecast	Variance 2015 - 2014
Direct Charges to Operating Areas	$11.9	$10.4	($1.5)
Allocated Charges to Operating Areas	38.0	39.8	1.8
Labor Adjustment	(0.8)	(0.8)	0.0
Subtotal IT Incurred	**49.1**	**49.4**	**0.3**
Labor Loadings Charged to Operating Areas	13.7	15.1	1.4
Corp Governance Allocation to Operating Areas	0.6	0.6	0.0
Subtotal IT Loaded	**$63.4**	**$65.2**	**$1.7**
2014 IT Deferral Mechanism	(6.9)	1.7	$8.5
Total IT	**$56.5**	**$66.9**	**$10.4**

* May not sum due to rounding.

As seen in Table 7, 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 account 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 706.

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 Section II, above and in PGE Exhibit 600, 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.

Q. Please explain the labor adjustment?

A. As discussed in PGE Exhibit 600, PGE applied two labor adjustments in its 2015 forecast. The first is a ($5.0) million labor adjustment to reflect (54.3) unfilled full time equivalent (FTE) positions over the entire company in the test year forecast. The allocated IT portion of this adjustment is approximately ($785,000) and represents (7.1) FTEs. The change in FTEs is summarized in Table 8, below.

Table 8
Total IT FTEs

Category	2014 Budget	2015 Test Year	Variance 2014 - 2015
Unadjusted IT FTEs	252.1	255.1	3.0
Labor Adjustment	(7.4)	(7.1)	0.3
Adjusted IT FTEs*	**244.7**	**248.1**	**3.3**

* May not sum due to rounding

Q. What is the second labor adjustment?

A. The second adjustment is ($1.0) million and is related to efficiencies we expect to realize from the myTime project (see also PGE Exhibit 600). The IT component of this adjustment is ($157,000). This adjustment affects labor cost only but does not impact FTEs.

D. 2020 Vision Update

Q. Please provide a brief summary of the 2020 Vision 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." In UE 262, we reiterated that the program's goal continues to be to implement common systems and standardized business processes throughout the enterprise to achieve efficiency and cost effectiveness. We also restated that 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. What 2020 Vision projects has PGE successfully implemented to date and what were their capital costs?

A. From 2010 through 2013, PGE completed the following 2020 Vision projects:

- <u>Work Management System (WMS) Upgrade</u>, $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 removed from service in 2015.
- <u>Finance and Supply Chain Replacement Project (FSRP)</u>, $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.

- 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).
- 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.
- "myTime" Time Collection System, $8.1 million - A web-based solution that captures time and labor data and automates complex rules, regulations, and union contract provisions regarding pay. In addition, myTime automates "leaves management" processes and accounts for contingent workers.

Q. What 2020 Vision projects have you forecasted to close from 2014 through 2015 and what are their estimated capital costs?

A. We expect to close the following:

- Maximo, Mobile and Scheduling Wave 2, $29.4 million estimated and expected to close in 2014 – To add functionality for T&D operations plus additional users (e.g., line crews and joint-use employees). PGE Exhibit 900 provides additional detail on this and the following two projects.

- Geographic Information System (GIS) and Graphic Work Design (GWD), $20.3 million estimated and expected to close in the first quarter of 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.
- Outage Management System, $17.7 million estimated and expected to close in the second quarter of 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.

Q. Did PGE include these amounts in its 2015 rate base for calculating the test year revenue requirement?

A. No. As noted in PGE Exhibit 300, Section VI, PGE's test year rate base is set at the December 31, 2014 level, and does not include 2015 additions to plant.

Q. Did you include any other costs associated with these projects in the 2015 forecast?

A. Yes. Because these projects will be providing benefit to customers for most of 2015, we included the following costs in the test year forecast:

- $0.5 million for software maintenance. Because IT projects such as GIS, GWD, and OMS involve vendor software, then annual license and maintenance agreement costs are necessary and prudent to operate the systems and keep them updated.

- $1.1 million for amortization. The 2020 Vision projects are amortized over 10 years beginning the month after closing to plant.

Q. Are you still developing the Customer Engagement Transformation (CET) program as an additional 2020 Vision project for future implementation?

A. Yes, PGE continues to develop the CET program to replace our current Customer Information System and Meter Data Management System. PGE Exhibit 1000 provides additional discussion of CET.

IV. Other A&G Cost Increases

A. Memberships

Q. Please explain the increase in the membership costs from 2014 to 2015.

A. PGE's membership costs are forecasted to increase from approximately $3.3 million to $3.6 million from 2014 to 2015. Membership costs for PGE's mandatory participation in WECC account for this increase.

Q. What accounts for the increase in the WECC membership?

A. As described in PGE's previous general rate case (PGE Exhibit 1000, UE 262):

> "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."

On January 1, 2014, WECC completed the separation into two entities:

- Peak Reliability (i.e., the Non-RE described above) will be responsible for: 1) reliability coordination; 2) interchange authority; 3) reliability coordinator training; 4) the western interconnection synchophasor program; and 5) system operating limits methodology for the operations horizon.
- WECC (i.e., the RE described above) will be responsible for: 1) developing electric reliability standards; 2) providing monitoring and enforcement activities for compliance with reliability standards; 3) providing event analysis and lessons-learned from system

events; 4) acting as a centralized repository of information relating to the planning and operation of the Bulk Electric System; 5) coordinating system planning and modeling; 6) providing information related to industry best practices; 7) facilitating resolution of market seams and coordination issues; 8) securing the sharing of critical reliability data; and 9) providing a robust stakeholder forum.

Because these entities will have separate administration, management, and Boards of Directors their costs are expected to increase significantly. To address this, PGE has increased its 2015 budgeted membership by approximately $150,000.

Q. Are any other changes expected to increase WECC membership costs?

A. Yes. Alberta Energy indicated that they would not participate in Peak Reliability (Peak), when it begins operations on January 1, 2014. This means that: 1) Peak's costs will be spread among fewer members; and 2) PGE's additional share of this membership cost is expected to be approximately $130,000.

B. Business Continuity and Emergency Management

Q. Please explain the cost increase for Business Continuity and Emergency Management (BCEM).

A. PGE's costs for BCEM are forecasted to increase from approximately $600,000 to $800,000 from 2014 to 2015. We base this increase on the development of a BCEM roadmap that establishes the activities PGE needs to perform through 2018 to achieve a target level of resilience among PGE's primary departments/systems.

Q. What is the purpose of the BCEM department?

A. BCEM was established in 2007 to support on-going evaluation, mitigation and response to significant events that may adversely affect service to customers, company assets, and employees. This includes providing planning support to recover critical functions as quickly as possible, in compliance with all regulatory requirements. This department establishes business continuity plans and procedures; conducts risk and business impact assessments; develops training programs and materials; and establishes and operates emergency operations center functions and facilities needed to effectively prepare for, respond to, and recover from, a variety of emergency events.

Q. What do you mean by "target level of resilience"?

A. Resilience is the ability of a department to quickly restore its performance to an operational level after some form of detrimental event. By detrimental event, we are referring to natural events (e.g., major earthquake or flood), technological events (e.g., a significant system or plant failure due to mechanical or physical issues), or man-made events (e.g., a successful cyber-attack or act of terrorism). In order to establish a department's resilience, the BCEM roadmap establishes a timeline for each primary department/system to undergo a cycle to:

- Establish plans to restore operations;
- Train employees on restoration procedure;
- Perform exercises to test employees; and
- Evaluate performance.

Subsequent to the final step, the cycle would be repeated.

Q. How is this different from your earlier efforts at BCEM?

A. It is different only in degree. Until 2012, BCEM operated with only three or less FTEs (not including two FTEs for support and administration). This has limited the number of areas within PGE that BCEM has been able to support with its full range of duties. With the growing recognition of the potential for detrimental events and the increasing emphasis on protecting critical energy infrastructure, PGE determined that its BCEM efforts needed to be accelerated. To this end, we have established the roadmap and budgeted for two additional FTEs in order to achieve the roadmap's timeline. This effort is also based in part on The Oregon Resilience Plan, issued in February 2013, which recommends that "Energy sector companies should institutionalize long-term seismic mitigation programs and should work with the appropriate oversight authority to further improve the resilience and operational reliability of their Critical Energy Infrastructure (CEI) facilities" (page 175).[7]

[7] The Oregon Resilience Plan is available at: http://www.oregon.gov/OMD/OEM/osspac/docs/Oregon_Resilience_Plan_Final.pdf

V. Conclusion

Q. Please summarize your request for A&G in this filing.

A. We request that the Commission approve the following:

- PGE's forecast of $154.9 million in A&G costs in the 2015 test year. This represents a $7.2 million increase from the 2014 budget and is primarily driven by increases in employee benefits (i.e., health care and dental premiums), environmental services, and insurance costs.
- The establishment of a regulatory asset with a 20-year amortization for the environmental remediation efforts along the Willamette River in downtown Portland, including the Downtown Reach and Portland Harbor. If approved, PGE would reclassify the $3.1 million environmental remediation costs included in the 2015 forecast and associated with the Downtown Reach, river miles 13.1 and 13.5, to that regulatory asset and begin amortization.

Absent the referenced cost increases (plus the increase associated with OPUC fees), PGE has held its 2015 A&G forecast flat with only a modest, overall 0.96% cost increase from 2014. We continue to 1) employ benchmarking tools to identify areas of improvement, and 2) to identify and develop programs as part of the multi-year benchmarking process to enhance our efficiency and effectiveness on an on-going basis.

VI. 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. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
701	Summary of A&G Costs and FTEs
702C	Summary of Insurance Policies/Premiums
703	Description of Insurance Coverage
704	Map of Downtown Reach Remediation Area
705	Methodology for Accounting Treatment of IT Project Costs
706	IT O&M Cost Summary by Operating Area
707	Efficiency Savings Summary

A&G Summary	Costs ($ millions)								FTEs							
	2010	2011	2012	2013	2014	2015	2014 to 2015		2010	2011	2012	2013	2014	2015	2014 to 2015	
Category	Actuals	Actuals	Actuals	(9+3)	Budget	Forecast	$ Delta	Annual %	Actuals	Actuals	Actuals	Thru (9)	Budget	Forecast	$ Delta	Annual %
Major Functional Areas																
Facilities and General Plant Maintenance	7.2	5.5	4.8	3.9	4.9	5.1	0.3	5.5%	12.2	11.7	12.9	12.9	13.0	13.0	-	0.0%
Accounting/Finance/Tax	8.5	10.2	9.1	9.0	9.5	9.9	0.4	4.3%	85.2	84.7	72.3	67.6	67.6	68.1	0.5	0.7%
HR/Employee Support (net of capital allocs.)	4.7	5.4	5.8	6.8	8.2	8.0	(0.2)	-2.2%	112.7	115.7	103.7	104.5	105.2	105.2	-	0.0%
Insurance / I&D	12.3	11.2	11.5	11.4	11.9	12.9	0.9	7.6%	6.5	6.6	6.6	6.7	7.0	7.0	-	0.0%
Legal	6.6	7.8	6.7	5.8	6.9	7.1	0.2	3.5%	28.4	27.8	28.0	27.4	27.9	27.9	-	0.0%
Regulatory Affairs	2.4	2.4	2.3	2.8	3.1	3.2	0.1	3.9%	28.4	29.4	32.0	31.7	34.0	35.0	1.0	2.9%
Corporate Governance	3.2	3.0	3.1	3.2	3.8	3.9	0.2	4.6%	13.9	13.8	14.3	14.2	13.8	13.8	-	0.0%
Business Support Services	2.7	2.7	2.8	2.7	2.9	3.0	0.1	3.1%	8.0	8.0	7.0	7.0	7.5	7.5	-	0.0%
Environmental Services	1.1	1.2	2.5	1.9	2.5	5.6	3.1	124.3%	-	-	-	-	-	-	-	#DIV/0!
Corporate R&D	0.2	0.9	0.9	0.7	1.5	1.5	0.0	2.7%	0.6	1.0	1.0	1.0	1.0	1.0	-	0.0%
Contract Services/Purchasing	1.0	1.0	1.3	1.4	1.5	1.6	0.1	4.2%	22.7	24.4	22.0	22.7	22.0	22.0	-	0.0%
Security and Business Continuity	1.2	1.1	1.3	1.3	1.9	2.2	0.2	12.1%	9.3	8.7	8.6	11.3	12.0	15.0	3.0	25.0%
Corp Communications/Public Affairs	1.9	1.7	2.1	1.9	1.9	1.9	(0.0)	-0.8%	22.1	21.8	25.7	25.8	26.4	24.4	(2.0)	-7.6%
Load Research	0.2	0.2	0.3	0.2	0.1	0.0	(0.1)	-89.3%	-	-	-	-	-	-	-	#DIV/0!
Hydro Licensing and Support	0.3	0.2	0.2	0.2	0.2	0.3	0.1	38.6%	-	-	-	-	-	-	-	#DIV/0!
Performance Management	0.9	0.9	1.3	1.3	1.6	1.6	0.1	3.5%	12.4	11.9	14.7	15.7	15.0	15.0	-	0.0%
Governmental Affairs	1.2	1.3	1.3	1.0	1.0	1.0	0.0	4.1%	12.2	13.2	12.4	10.3	11.3	11.3	-	0.0%
Subtotal	55.6	56.8	57.2	55.3	63.4	68.9	5.5	8.7%	374.5	378.7	361.1	358.8	363.5	366.0	2.5	0.7%
Other A&G Costs																
IT: Direct & Allocated	8.2	11.5	11.6	10.8	12.2	12.7	0.5	4.5%	266.0	251.2	249.8	241.0	252.1	255.1	3.0	1.2%
Corporate Cost Reductions	-	-	-	(1.3)	(2.2)	(2.2)	-	0.0%				-	(17.9)	(17.2)	0.7	-3.9%
Other Membership Costs	2.0	2.5	2.7	2.6	3.3	3.6	0.3	9.1%								
Incentives	11.3	16.2	15.4	14.7	8.8	8.9	0.1	1.4%								
Severence	2.1	0.7	1.0	0.4	-	-	-	#DIV/0!								
Regulatory Fees	4.4	6.6	6.1	6.0	6.3	7.0	0.7	11.1%								
General Plant Maint.	1.3	1.6	2.9	2.3	2.5	2.5	(0.0)	-1.6%								
Total PTO to A&G	4.5	6.1	5.2	5.6	5.3	5.5	0.2	4.4%								
Benefits (net of capital allocs.)	35.8	42.0	48.9	54.5	51.9	53.0	1.1	2.1%								
Corp Allocations	(4.8)	(3.9)	(7.1)	(3.4)	(6.2)	(6.3)	(0.1)	1.8%								
Revolver Fees, Margin Net Int., & Broker fees	-	3.0	2.0	2.5	2.5	1.3	(1.2)	-46.5%								
Subtotal	64.8	86.4	88.7	94.7	84.4	86.0	1.7	2.0%								
TOTAL A&G	120.4	143.2	145.9	149.9	147.7	154.9	7.2	4.9%	640.4	629.9	610.8	599.8	597.7	603.9	6.2	1.0%

Exhibit 702C

Confidential

Exhibit 703

PGE's Insurance Policies

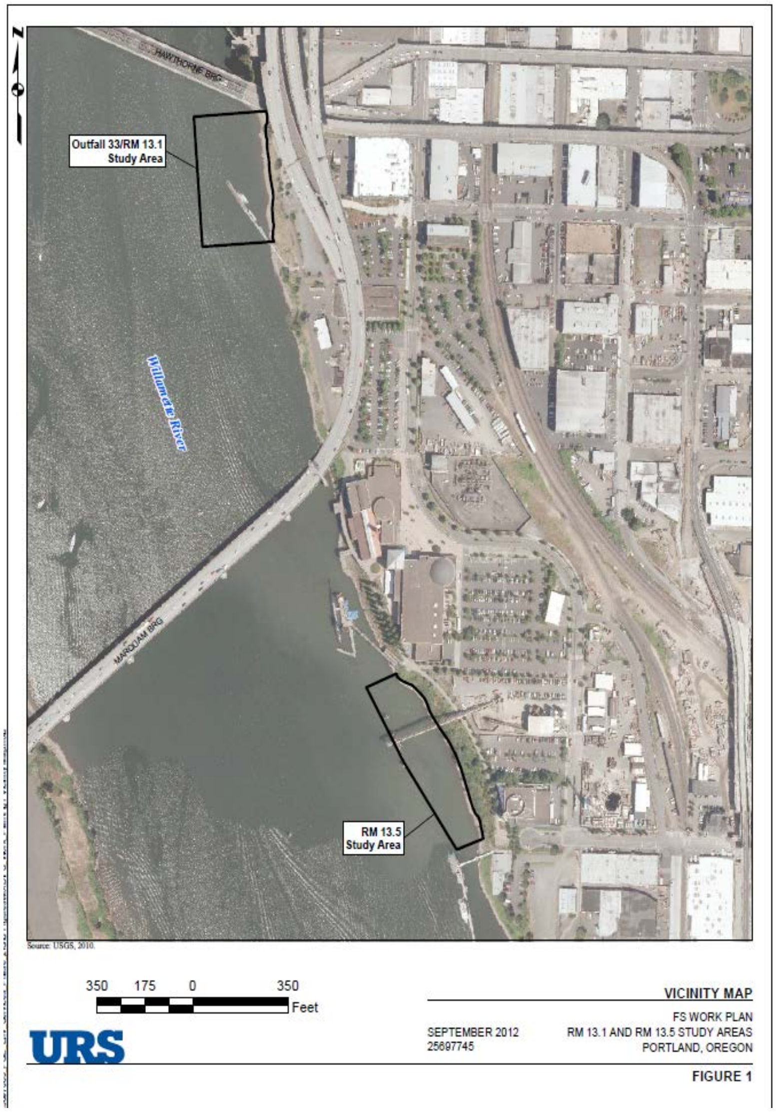
Insurance Policy	Description
All Risk Property	PGE's main property insurance program is led by FM Global and insures PGE's property such as power plants, substations, office buildings, etc. from "all-risks" of direct physical loss or damage (including boiler and machinery), subject to policy exclusions, 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 $960 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 aerial 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.

PGE Exhibit 704

May of River Mile 13.1 to 13.5

Remediation Area



<u>PGE's Methodology for the Accounting Treatment of Information Technology Project Costs</u>

The following narrative describing PGE's methodology for the accounting treatment of information technology project costs complies with generally accepted accounting principles (GAAP) as detailed in Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 350-40 Intangibles – Goodwill and Other - Internal-Use Software.

<u>CRITERIA FOR CAPITALIZING COMPUTER SOFTWARE</u>

Software systems/applications meeting the following guidelines are capitalized by PGE as Intangible Assets (FERC Account 303) and amortized on a straight-line basis.

1. The application or enhancement must result in the addition of a new function or a new program.

    a. A new function is defined as modifications to existing internal use software that results in enabling the software to perform tasks that it was previously incapable of performing. Upgrades/enhancements normally require new software specifications and may also require a change to all or part of the existing software specifications.

2. The application/enhancement must have an expected life of at least five years at the time of installation.

3. PURCHASE/DEVELOPMENT – The direct cost dollar amount must equal/exceed **$250,000** for systems meeting capital criteria. This type of software is discussed at length below where an application may be developed from the ground up, to where an application is purchased and costs are incurred to enhance/upgrade for company business.

<u>ACCOUNTING TREATMENT</u>

The following table illustrates the stages and related processes of computer software development. These are used to identify the appropriate accounting treatment - Capital or Expense – depending on the types of activity occurring during a project. Discussion of various types of activities within each stage follows the table to provide further clarification.

Preliminary Project Stage Accounting Treatment – **Expense**	*Application Development Stage* Accounting Treatment – **Capital**	*Implementation/Operation Stage* Accounting Treatment – **Capital/Expense**

Planning Feasibility or Consulting Study Business Process Redesign Requirement Analysis	Design Construction/Coding Testing, including parallel processing phase	Implementation Training Application maintenance Modifications to another system

PRELIMINARY PROJECT STAGE

1. Planning – Work performed to identify business direction and needs, then to develop a system or technology plan:

   - Providing clear understanding of an organization's goals and objectives under the current business environment.
   - Preparing architecture for leveraging information technology to meet goals and objectives.
   - Developing multi-year information systems/technology plans.
   - Planning for Disaster Recovery and associated Contingency plans.

Accounting Treatment - Expense

2. Feasibility or Consulting Study – Work to study, analyze, or evaluate current practices, processes, or procedures in order to determine what, if anything needs to change.

   - Identifying strengths and weaknesses of current operations and information systems.
   - Conducting a feasibility study to identify probable costs and benefits of some action.
   - Assessing performance levels.
   - Determining project scope and boundaries for potential projects (i.e., identifying business processes or functional areas to be included, excluded, or altered).
   - Identifying problems/opportunities needing immediate action.
   - Invite vendors to perform demonstrations of how software will fulfill needs.
   - Select a consultant to assist in the development or installation of the software.

Accounting Treatment - Expense

3. Business Process Redesign – Used in business areas where it is believe there are significant opportunities for improving work processes before system development activities begin. Activities included:
   - Documenting "current state" business processes in detail.
   - Collecting process performance attributes such as cycle time, resources consumed, work volumes, and processing efficiency.
   - Conducting value and/or root cause analysis.

- Designing "future state" processes.
- Defining information models and technology enablers.
- Developing detailed cost-benefit analyses

If this step is skipped, a slightly modified version of these activities is performed in the Requirements Analysis stage. The need for an information system is validated and often further defined upon the completion of this stage.

Accounting Treatment - Expense

4. Requirements Analysis - Once it is determined that existing software needs to be changed or new software acquired by construction or package acquisition, information system requirements are gathered. Activities include:

   - Identifying key business/information requirements. May include steps to document current/future processes, evaluate performance attributes, and perform value analysis on processes if a business process analysis was not performed.
   - Developing a conceptual design for the new system.
   - Sending Requests for Proposals (RFPs) to vendors.
   - Evaluating software packaged-based solutions to determine whether to purchase or design a system.
   - Finalizing the cost - benefit analysis.
   - Determine that the technology needed exists.
   - Explore alternative means of achieving performance requirements, (i.e. should the software be purchased or built?)

Accounting Treatment - Expense

The actions in the Preliminary Project stage may be performed in a different order than described, but most do occur at some level at the start of a project.

At the completion of the Requirements Analysis step, the scope and technical feasibility of the specific system to be developed will be clarified, and costs can be estimated with a high degree of certainty.

Capitalization of costs will begin when the Preliminary Requirements are completed, and management commits to funding the project, and that it is probable that the project will be completed and the software will be used to perform the function intended.

APPLICATION DEVELOPMENT STAGE

1. Design (Specific) – Includes design of technical components of the new system, and development of plans for construction and testing. Specifications for software and hardware components are developed, and products acquired/installed.

2. Construction and Testing – Costs to build/program the system, conduct various tests to ensure system integrity, and to develop training and implementation plans.

Capitalized costs included in these stages include:

- External direct costs of materials and services – contract labor, software purchased to support construction of application, materials, services, travel expenses incurred by employees as part of their job directly associated to the development.
- Operating Area Labor – Operating area employees (non-IT) assisting with a project should charge normal operating accounts unless time on a project is expected to exceed 3 months.

Accounting Treatment – Capital
Capitalization ends when the software is substantially complete and ready to be placed into service – classified as “used and useful”.

<u>IMPLEMENTATION/OPERATION STAGE</u>

1. <u>Implementation</u> – Activities to bring the system in to production where it is “used and useful”:

   a. Data Conversion – Costs to build or acquire software to convert automated/electronic data.
   b. Interface Programming – Costs to construct interfaces between the new and existing systems.
   c. Programming of System Reports – Costs to develop new or rebuild existing reports from data in the new system.

   Accounting Treatment:
   Before System is Operational – Capital
   After System is Operational – Expense

   d. Data Conversion – Activities to process/convert data from an existing system into the new system.

   Accounting Treatment – Expense

2. <u>Training</u> – Planning, developing, and delivering training to operators on the use of the new system (trainer costs).

   Accounting Treatment:
   Before System is Operational – Capital
   After System is Operational – Expense

   Operator or client time to attend training on how to use the new system (trainee costs).

   Accounting Treatment – Expense

3. <u>Application Maintenance</u> – Costs of an annual maintenance agreement for the new system.

Accounting Treatment – Expense

Over life of the agreement

4. <u>Modifications to Another System</u> – Costs to modify other systems due to the development of the new system.

   Accounting Treatment – Expense
   Unless it meets the guidelines above for meeting capital treatment as an enhancement or increase in functionality.

<u>RELATED PROJECT ACTIVITIES</u>

Data Creation – Costs to create data not currently available in an electronic version are charged to expense.

Data Cleanup – Costs to edit or otherwise clean up existing data for accuracy in order to make it more functional is expensed.

Costs After System is Operational – Once a system is "used and useful" for its intended purpose, subsequent costs are expensed unless they meet the guidelines above for capitalization as functional enhancement. Includes the phasing in of a system over an extended period of time or in multiple locations/sites.

Exhibit 706
IT Summary by Operating Area

Funtion	2010 ACTUALS	2011 ACTUALS	2012 ACTUALS	2013 (9+3)	2014 Budget	2015 Budget	2015-2014 Delta	Annual % delta 2015-2014
Production								
Assigned	608,454	362,389	202,365	91,496	-	-	-	#DIV/0!
Allocated	3,892,290	6,019,105	6,151,591	5,382,251	7,140,936	7,575,280	434,344	6.08%
Total Production	4,500,744	6,381,494	6,353,956	5,473,748	7,140,936	7,575,280	434,344	6.08%
Power Operations								
Assigned	764,101	635,983	686,177	702,439	502,311	522,907	20,597	4.10%
Allocated	780,153	1,590,556	1,826,800	1,789,208	1,379,196	1,599,447	220,250	15.97%
Total Power Ops	1,544,254	2,226,538	2,512,977	2,491,647	1,881,507	2,122,354	240,847	12.80%
Transmission								
Assigned	960,033	579,676	454,204	405,491	514,827	732,578	217,751	42.30%
Allocated	462,973	643,982	668,580	1,152,184	1,509,413	1,599,911	90,498	6.00%
Total Transmission	1,423,006	1,223,658	1,122,784	1,557,676	2,024,240	2,332,489	308,249	15.23%
Distribution								
Assigned	1,373,265	1,951,077	356,867	1,723,569	753,144	724,718	(28,426)	-3.77%
Allocated	9,688,338	14,572,652	15,168,671	13,340,204	17,658,511	18,717,241	1,058,730	6.00%
Total Distribution	11,061,603	16,523,729	15,525,538	15,063,773	18,411,655	19,441,959	1,030,304	5.60%
Customer Acctg/Svc								
Assigned	4,713,759	4,083,132	3,359,540	2,411,494	2,348,763	2,542,369	193,606	8.24%
Allocated	8,059,444	8,437,246	8,746,898	10,686,028	14,201,468	15,052,928	851,461	6.00%
Total Customer Acctg/Svc	12,773,203	12,520,379	12,106,438	13,097,522	16,550,231	17,595,297	1,045,067	6.31%
A&G								
Assigned	5,184,063	6,803,082	7,701,300	6,692,012	7,775,147	5,860,044	(1,915,103)	-24.63%
Allocated	5,516,168	7,873,198	8,065,032	8,325,513	10,432,188	11,039,792	607,604	5.82%
Total A&G	10,700,231	14,676,279	15,766,332	15,017,525	18,207,336	16,899,837	(1,307,499)	-7.18%
Totals								
Assigned	13,603,675	14,415,339	12,760,454	12,026,503	11,894,192	10,382,616	(1,511,575)	-12.71%
Allocated	28,399,365	39,136,739	40,627,572	40,675,389	52,321,712	55,584,599	3,262,887	6.24%
Grand Total	42,003,040	53,552,078	53,388,026	52,701,891	64,215,904	65,967,216	1,751,312	2.73%
2014 IT Deferral (UE 262)					(6,947,200)	1,737,000		
Labor Adjustment					(784,936)	(784,936)		
Adjusted Total	42,003,040	53,552,078	53,388,026	52,701,891	56,483,768	66,919,280	10,435,512	18.48%

Efficiency Savings Summary
Cumulative savings through 2014 and 2015
($ in millions and in 2014 dollars)

		A	B	C	D	E	F
	Initiative	Savings 2014	Changes 2014	Annual Cumulative Revised 2014	Savings 2015	Annual Cumulative Savings 2015	Comments
1.	A&G - Procurement Efficiency via Strategic Sourcing (1)	1.1		1.1		1.1	
	TOTAL A&G	**$ 1.1**		**$ 1.1**		**$ 1.1**	
2.	F&A - Financial System Replacement Project (FSRP) and Work Process Analysis	1.5		1.5		1.5	
3.	F&A - 1% Rebate on P-Card Purchases (1)	0.1		0.1		0.1	
	TOTAL FINANCE AND ACCOUNTING	**$ 1.6**		**$ 1.6**		**$ 1.6**	
4.	HR - General	0.8	0.1	0.9		0.9	We expect additional FTE savings of $0.1 million due to the elimination of a Manager I position in HR.
5.	HR - myTime	1.0		1.0		1.0	Benefits realized by myTime can be categorized into three areas: 1) FTE reduction, 2) automation of laborious manual processes, 3) self-directed employee timekeeping, for an on-going savings of $1 million annually.
7.	HR - Employee Benefit Mitigation Efforts						
	In-source health and welfare administration	0.3		0.3		0.3	
	Self-Insured MetLife Dental (1)	0.1		0.1		0.1	
	Higher Deductibles, Increased Co-Pays	0.8		0.8	0.6	1.4	For 2015, PGE continues to make design changes to our non-union medical plans to reduce healthcare rate increases. The design changes effective in 2014 and continuing in 2015 and beyond result in increased employee deductibles, co-insurance, and out-of-pocket limits. Our current estimate of non-bargaining, active medical and dental plan expense for 2015 is approximately $25.0 million. Without the additional plan design changes effective in 2014, the 2015 benefit expense would have been $25.6 million, resulting in a savings of approximately $0.6 million. This $0.6 million is in addition to $0.8 million of savings resulting from plan design changes in 2013.
	Vendor Change for Pre-1992 Non-Union Medicare Supplemental Plan	0.7		0.7	(0.2)	0.5	As a result of the vendor change for the management of the Non-Union Medicare Benefit Plan, PGE expects approximately $6.5 million in savings over 12 years. The actual benefit amount changes each year but the average savings over the 12 years is approximately $0.5 million per year. The savings reported in the early years was slightly higher than average resulting in the 2014 forecast of $0.7 million.
	401(k) Administration Provider Change	0.8	(0.8)	-		-	We removed $0.8 million in previously reported savings. We erroneously counted these savings in the 2014 test year forecast. While PGE has realized savings, the 401(k) Administration Provider fees are not included in our retail rates because the fees are paid by employee participants in the 401(k) plan. Therefore, we removed these savings from the cumulative total.
	Reduced Actuarial Fees	-	0.2	0.2	0.1	0.3	PGE solicited request for proposals (RFP) related to pension and other post-retirement actuarial services. Through the RFP, PGE was able to achieve both cost savings and added efficiency by consolidating services to one actuary for both our pension and Voluntary Employee Beneficiary Association (VEBA) plans. This consolidation resulted in $0.3 million in savings over the three-year contract, with $0.1 million expected in 2015.
	TOTAL HUMAN RESOURCES	**$ 4.5**	**$ (0.5)**	**$ 4.0**	**$ 0.5**	**$ 4.5**	
8.	IT - Vision Design / General	0.8	1.2	2.0		2.0	In UE 262, PGE forecasted an avoided cost savings of $3.3 million based on the number of virtual servers in place as of the end of calendar year 2012. PGE continues to leverage the use of virtual servers over physical servers. Virtualized server builds take hours versus days for physical servers. We had 170 virtual servers in 2009 and 1,257 in 2013. For each virtual server we purchase versus buying a physical server, we avoid spending approximately $5,500 per server, which equates to approximately $6.0 million of additional avoided cost in 2013 relative to 2009.
9.	Reduce hw/sw maintenance due to Office of CIO		0.8	0.8		0.8	PGE created the Office of the Chief Information Officer, which consolidates three separate functions, (vendor management, planning and architecture) into one function. This change results in better alignment of the hardware and software maintenance budgets and reductions of those budgets along with better utilization of PGE resources. The total cumulative savings is $0.8 million.
10.	IT - Application Management	0.6		0.6		0.6	
11.	IT - Agile Initiatives (1)	0.4		0.4		0.4	
12.	IT - Virtual Servers (1)	3.3	2.7	6.0		6.0	PGE forecasted an avoided cost savings of $3.3 million based on the number of virtual servers in place as of the end of calendar year 2012. PGE continues to leverage the use of virtual servers over physical servers. Virtualized server builds take hours versus days for physical servers. We had 170 virtual servers in 2009 and 1,257 in 2013. For each virtual server we purchase versus buying a physical server, we avoid spending approximately $5,500 per server, which equates to approximately $6.0 million of additional avoided cost in 2013 relative to 2009.
	TOTAL INFORMATION SYSTEMS	**$ 5.0**	**$ 4.7**	**$ 9.7**		**$ 9.7**	

13.	T&D - Transformation O&M Savings						
	Centralization of Regional Line Dispatch	0.3	(0.2)	0.1	0.1	0.1	Although the consolidation of the Regional Line Dispatch is complete, the additional savings will be delayed until 2016 and beyond. After consolidation was completed, we discovered additional tasks and process improvements that needed to be implemented to improve our efficiency. PGE employees are currently working on those process improvements as well as learning and mastering the new systems. In 2015, Next Wave, discussed in PGE Exhibit 900, will be deployed and additional time will be needed as employees adjust to this system. Next Wave, when fully implemented, will provide dispatchers with the right tools and resources to dispatch a greater number of crews in the future and ultimately lead to reduction of equipment rental and contract costs.
	M&S Maximo Wave 1	0.2		0.2		0.2	
	Off - Shift Crews	0.7		0.7		0.7	
	Supervisor in the Field (SITF)	0.8	(0.1)	0.7		0.7	There was a slight reduction in the amount of overtime savings forecasted. After the initiative was implemented, we reevaluated the amount of savings forecasted and decided that more time was needed for the program to stabilize before we determined the total amount of savings that could be achieved.
	Fleet Optimization	0.2		0.2	0.1	0.2	For 2015, we are expecting an additional $0.1 million in savings primarily attributable to further fuel savings in our Fleet Optimization initiative.
	Service Coordinator	0.1		0.1		0.1	
	Super Crew		0.2	0.2		0.2	Super Crew refers to the combining of two crews. In the past, PGE sent out a three-man crew to set the pole, followed by a four-man crew to transfer wire and equipment to the pole. Now the Super Crew is a five-man crew that sets the pole and transfers the wire, which saves a second trip to the job site and avoids the cost of a second flagging crew.
	Civil Crew Contractor Strategy		0.2	0.2		0.2	Civil Crew refers to the group of journeyman employees responsible for construction work at substations; duties include grading, digging, concrete foundations, fences, and placing rock. PGE has reduced the staffing in this work group by half since implementing a flexible resource strategy that uses contractors to complete some of these construction activities during peak construction times.
	Other	1.2	(0.2)	1.0	0.2	1.2	The primary reason is within Design and Engineering Centralization. PGE was unable to capture the full reduction of four timekeepers. We reduced FTEs by two and two transferred to Human Resources in the fourth quarter of 2013. For 2015, we are expecting an additional $0.2 million in savings primarily attributable to Lean process improvements.
14.	T&D - FTE reduction		0.8	0.8		0.8	PGE has identified a reduction of 8 FTE positions. Lean process review and functional reorganization is expected to result in broader management span of control, and thereby a resulting lower FTE requirement.
	TOTAL TRANSMISSION AND DISTRIBUTION	**$ 3.4**	**$ 0.7**	**$ 4.1**	**$ 0.3**	**$ 4.4**	
15.	Gov't Affairs/ Public Policy - FTE reduction		0.1	0.1	0.1	0.2	Public Policy has evaluated its workload and after reorganizing and consolidating some employee duties, it will reduce its staff by one FTE (specialist position) in 2015, which will save approximately $0.1 million.
	TOTAL GOVERNMENT AFFAIRS/PUBLIC POLICY		**$ 0.1**	**$ 0.1**	**$ 0.1**	**$ 0.2**	
16.	Customer Engagement Transformation		0.8	0.8	0.7	1.6	The Increased Paperless Billing Adoption project is forecasted to yield efficiencies and savings of approximately $0.4 million. The Customer Contact Center is expected to introduce a set of initiatives in 2015 that will focus on front-end process streamlining, create efficiencies, and reduce back office processing. PGE's Interactive Voice Response (IVR) system will be enhanced to allow for self-service transactions, in addition to streamlined call processes that we expect will create efficiencies in the Contact Center. These improvements will focus on reducing hold times and we are expecting to resolve the customer's concern with the first call they make to PGE.
17.	Customer Service - FTE reduction		0.2	0.2		0.2	With the automation of meter reading to smart meters and remote connect capabilities, PGE is reducing two field connect representatives and a supervisory position for a total cumulative savings of $0.2 million in 2015.
	TOTAL CUSTOMER SERVICE		**$ 1.1**	**$ 1.1**	**$ 0.7**	**$ 1.8**	
	O&M Efficiency Savings	**$ 15.6**	**$ 6.1**	**$ 21.6**	**$ 1.7**	**$ 23.3**	

(1) Avoided costs

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 283

Production O&M

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Stephen Quennoz
David Weitzel

February 13, 2014

Table of Contents

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 Analyst, Financial Analysis Group.

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) costs associated with PGE's long-term power supply resources, both owned plants and contracts. We discuss recent plant performance and our ongoing efforts to improve plant performance, reliability, and safety. We also discuss PGE's potential acquisition of Power Resources Cooperative's (PRC) 10 percent ownership share of the Boardman plant. Lastly, we discuss PGE's implementation and participation in an Energy Imbalance Market (EIM).

Q. How is the remainder of your testimony organized?

A. Our testimony has four additional sections. In Section II, we discuss PGE's generation resources, including the resources selected through the 2009 Integrated Resource Planning (IRP) process and the recent performance of our resources. In Section III, we discuss operations and maintenance practices; PGE's forecast of the 2015 test year Production O&M expenses; and, expected thermal operations and maintenance events during the 2015 test year. In Section IV we discuss the two developing Energy Imbalance Markets. In Section V we discuss the negotiations with Power Resources Cooperative (PRC) to acquire their 10 percent ownership share of the Boardman Coal Plant (Boardman). In Section VI we present our 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 2015 test year?

A. Yes. PGE Exhibit 801 lists PGE's generating resources and their expected energy output as modeled under normal hydro conditions for PGE's initial 2015 Net Variable Power Cost (NVPC) forecast presented in PGE Exhibit 500.

Q. Have PGE's long-term power supply resources changed significantly since the UE 262 rate case?

A. Yes. Pursuant to PGE's 2009 IRP process, the Commission acknowledged action plan, and the subsequent request for proposals (RFP), PGE is adding a flexible capacity resource, Port Westward 2 (PW2), and a wind resource, Tucannon River Wind Farm (Tucannon), in 2015. PGE also anticipates a new base load energy resource, Carty, to come on line in 2016. However, no costs for Carty are included in the 2015 test year.

Q. Which resources selected through the IRP process are included in this general rate case proceeding?

A. PW2 and Tucannon are included in this general rate case proceeding. A full discussion of PW2 and Tucannon is presented in PGE Exhibit 400 and their respective revenue requirements in PGE Exhibit 300.

B. PGE Plant Performance

Q. What are PGE's goals for generation plant performance?

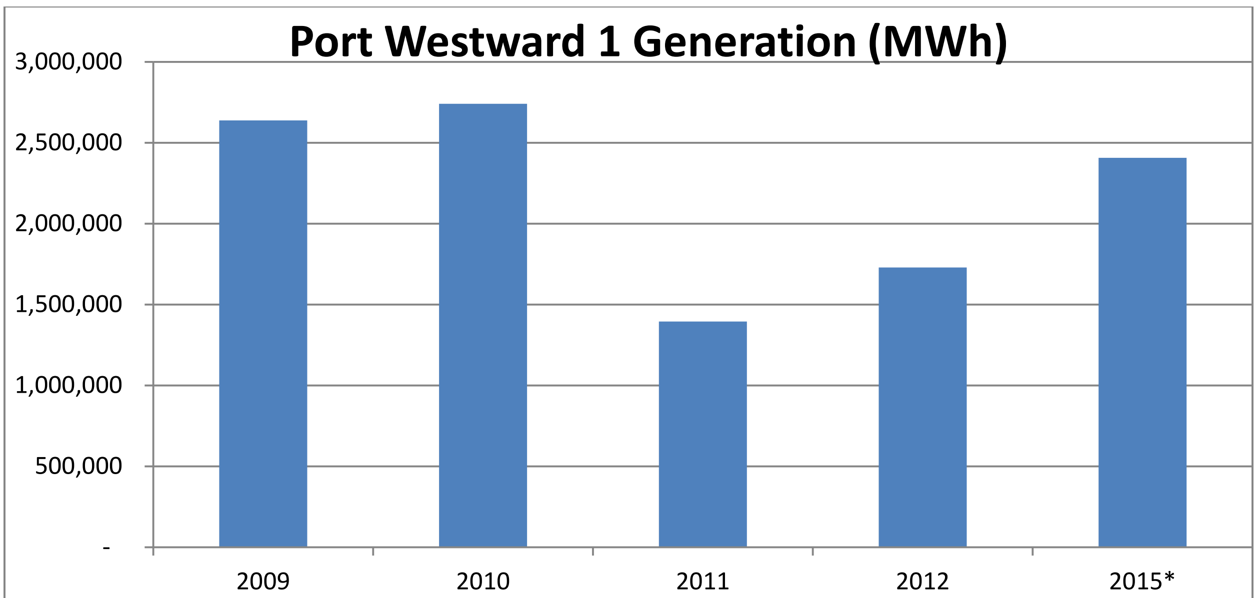
A. The performance and availability of PGE's generating resources are top priorities for the Generation organization. As a long-term goal, we target plant performance and availability in the top-quartile of an industry peer group. On a year-to-year basis, realized plant availability is a key factor in evaluating the Generation organization.

Q. Please discuss PGE plant performance during 2012.

A. In 2012, the majority of PGE's plants exceeded the stated goals for performance in terms of cost per unit of output and availability. Port Westward 1 was again recognized in the top-20 for heat rate of a gas-fired resource.[1,2] Similar to 2011, we experienced an above-average hydro year during 2012 causing lower regional market prices, which displaced some thermal resources during late spring and early summer. We also observed a downward trend in natural gas prices through 2012.

Q. How did Port Westward 1 dispatch in 2012 compared with prior years?

A. The graph below summarizes Port Westward 1 generation, demonstrating the recent lower generation level relative to prior years and to PGE's current 2015 forecast in this filing.

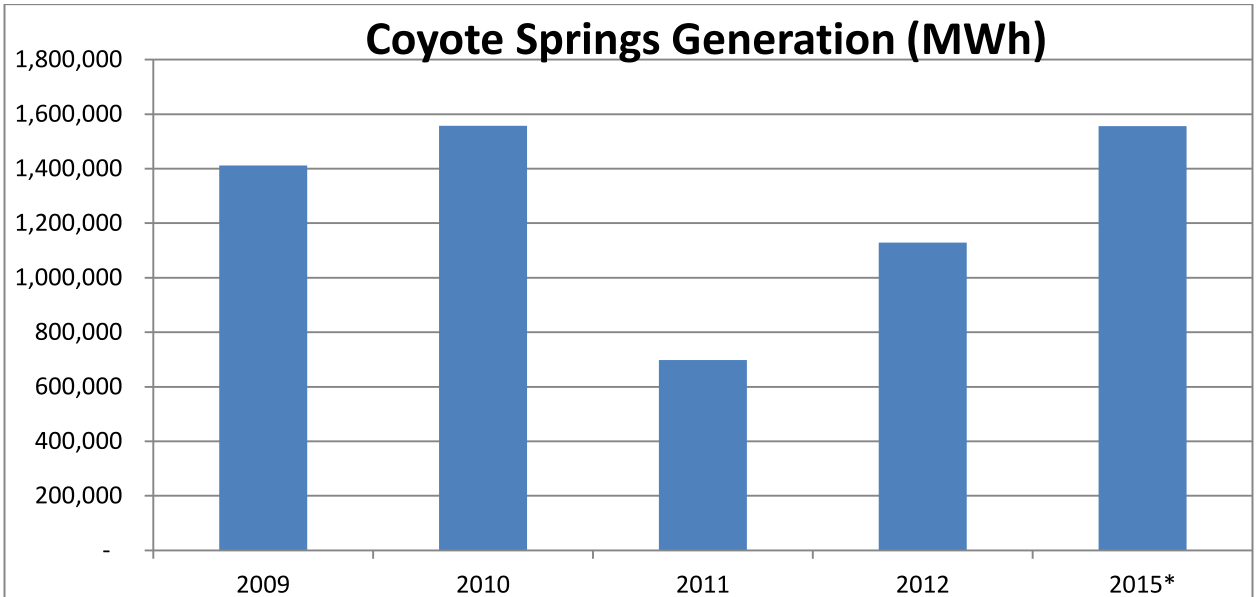


Source: PGE MFR #Actual PGE Thermal Generation Monthly 1998-2012 - Gas.xlsx, M610PUC10-00n-2015 GRC.xlsm, *2015 based on initial NVPC forecast presented with this filing.

[1] 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).
[2] As reported by "Electric Light & Power": http://www.elp.com/articles/print/volume-91/issue-6/features/2012-operating-performance.html

Q. Does Coyote Springs' dispatch follow the same pattern as Port Westward 1's?

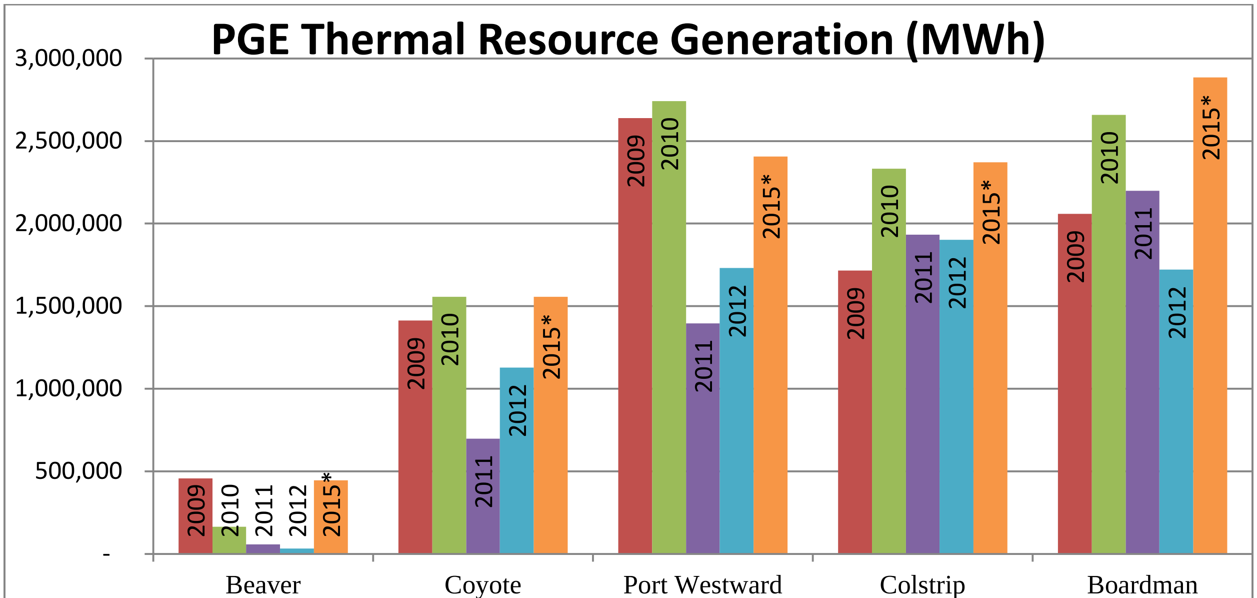
A. Yes. As seen in the chart below, Coyote Springs' 2012 dispatch increased from 2011, but remained lower than previous years.



Source: PGE MFR #Actual PGE Thermal Generation Monthly 1998-2012 - Gas.xlsx, M610PUC10-00n-2015 GRC.xlsm, *2015 based on initial NVPC forecast presented with this filing.

Q. Were all of PGE's thermal resources affected by the market conditions?

A. To some extent. Generation at Colstrip remained relatively flat compared to 2011, but was lower than 2010. As stated above, both Port Westward 1 and Coyote Spring had increased generation in 2012 compared to 2011, but generation levels were still lower than prior years. Boardman had decreased dispatch in 2012 compared to 2011 and prior years because the plant was economically displaced for a portion of the year. We summarize PGE's thermal plant generation for 2009-2012 in the chart below, along with PGE's current 2015 forecast for each of our existing thermal resources.



Source: PGE MFR #Actual PGE Thermal Generation Monthly 1998-2012 - Gas.xlsx, #Actual PGE Thermal Generation Monthly 1998-2012 - Coal.xlsx, M610PUC10-00n-2015 GRC.xlsm, *2015 based on initial NVPC

Q. How have PGE's plants performed recently?

A. Generally, PGE's plants performed well in 2013; however, some of PGE's thermal plants experienced extended outages:

- On July 1, 2013, Boardman was taken off-line when the plant sustained damage to the cold reheat piping, its supports and hangers, plant structural members and other plant components caused by a water hammer event. The damage was caused by the cold reheat line colliding with equipment and structures. This resulted in an outage lasting 30-days. Boardman returned to full-capacity operation on July 31.
- The Coyote Springs plant was taken off-line for several periods in 2013.
- On July 1, 2013, Colstrip Unit 4 tripped off-line due to an electrical fault in the generator. Inspection of the unit found significant damage to the generator core and rotor. Colstrip Unit 4 returned to full-capacity operation on January 24, 2014.

We discuss these outages in more detail below.

1. Boardman

Q. Please describe the outage at Boardman.

A. Boardman went offline on July 1, 2013. During a restart, the cold reheat line (CRH line) sustained damage due to a water hammer event. The CRH line directs steam from the High Pressure (HP) turbine back to the boiler reheater for further heat addition in order to improve efficiency. The source of the water was the reheat steam line attemperator, the device that cools superheated steam, when required, with cooler main feedwater to protect from overheating. After the plant inadvertently shutdown, the attemperator either continued or began leaking feedwater. As part of the standard plant restart procedure, steam was admitted to the HP turbine and the cold reheat non-return check valve opened. As the check valve opened, superheated steam mixed with saturated steam (a steam water mix) created by the attemperator leak, causing the water hammer event. This mixing resulted in a traveling pressure wave that lifted the CRH line and caused the hangers and restraints to break loose resulting in the damage discussed above.

Q. Has PGE performed a root cause analysis of the outage at Boardman?

A. Yes. The analysis identified the sequence of events leading up to the equipment failure. The analysis also outlined a number of possible actions that can be undertaken to prevent a recurrence of the problem.

Q. How will PGE incorporate the "lessons learned" in its operations at Boardman?

A. The recommendations from the root cause analysis report fall into three categories:

- Plant modification – Determine which plant components are required for efficient operation and remove components where the removal would reduce risk of similar incidents occurring without impacting plant operation and efficiency.

- Education – Develop and implement additional training programs including simulator training that mimics the event.
- Administration – Improve documentation of abnormal events and refine start-up procedures.

PGE is implementing the report's recommendations in all three areas.

2. Coyote Springs

Q. Please describe the outages at Coyote Springs.

A. The Coyote Springs plant started plant operations in 1995. The plant utilizes a General Electric (GE) steam turbine (ST) to generate power from waste heat recovered from the gas turbine. The steam is formed in the heat recovery steam generator (HRSG). In October 2012, ST bearing vibration levels started to increase, and reached the alarm level (6 mils) in February 2013. The plant was shut down for on-site inspection and testing to determine the cause(s). Nothing significant was found (no surface cracks were detected). Balance weights were installed to reduce rotational imbalance, and the plant was restarted. Vibration levels were lower than pre-outage levels, but subsequently began to increase. Additional balance modifications were made, but they were unsuccessful.

The plant was shut down in April 2013 and again no major problems were discovered. Magnetic particle testing (MT) was performed on the ST rotor to check for cracks, but none were found. The rotor was shipped offsite for more detailed inspection and testing at GE's repair shop in Bangor, Maine. GE's analysis indicated a problem with the mid-span coupling that connects the high pressure (HP) and low pressure (LP) sections of the ST rotor. Disassembly and inspection of the mid-span coupling revealed fretting and relaxation of the coupling bolts (the bolts are tightened during installation to provide the proper clamping force). The fretting to the coupling surface was repaired (this surface is normally inaccessible) and new bolts were installed and tightened to achieve the proper pre-load. The rotor was balanced in a high-speed spin-balance pit and returned to Coyote Springs.

The plant resumed operation in July 2013. On August 16th vibration levels on the unit began to shift and increase. On August 24, the unit tripped on high vibration. Multiple balance adjustments were unsuccessful, and the plant was again taken off-line on August 29th. Non-Destructive Examination (NDE) using surface methods revealed a crack in the ST rotor shaft at the transition radius between the low pressure (LP) turbine shaft and the mid-span coupling bolt flange. Although the same area was inspected during previous shutdowns using MT, a crack must be open to the surface (surface connected) to be reliably detected with MT or liquid penetrant (PT) methods. By August the crack had propagated to the surface and had progressed about 170 degrees circumferentially around the shaft.

The rotor was shipped offsite to Alstom for metallurgical examination and repair. Alstom was selected based on their extensive expertise with ST rotor weld repairs, including the successful repair of the Boardman ST rotor. The cracked portion of the LP coupling was removed and replaced with weld material, then machined to form a new LP coupling flange. The HP side of the coupling was examined to verify that a similar corrosion and cracking problem did not exist. The rotor was high-speed balanced and shipped back to Coyote Springs. The rotor was installed and the plant successfully returned to power generation on November 30, 2013. ST rotor vibration readings are now well-below the pre-outage condition (2 mils or less) and well below alarm limits.

Q. Has PGE performed a root cause analysis of the outage at Coyote?

A. Yes. PGE retained Alstom to perform both a Metallurgical Evaluation and Root Cause Analysis. Alstom's Metallurgical Evaluation included a complete chemistry mechanical properties testing. The cracking was examined with both optical and Scanning Electron Microscope (SEM) instruments.

Q. What did the root cause analysis identify?

A. The evaluation and analysis determined that the rotor crack originated in the rabbet fit area on the mid-span coupling face. Significant corrosion pitting was found in the mid-span coupling face area and the primary crack started at the root of a corrosion pit. A secondary crack, caused by high cycle fatigue, started about 1.5 inches in on the primary crack and grew until it reached the surface of the shaft.

Deep corrosion pitting can be caused by contaminants such as sulfides and chlorides in a wetted area. The rabbet fit geometry between the two components of the rotor creates a capture area that can entrap moisture and contaminants. Some minor indications of sulfides and chlorides were found in some of the samples of the cracked area; however, the source of the contaminants could not be determined. Although the age of the crack could not be determined, "the fact that the rotor has not completely failed in spite of the extensive cracking suggest that the conditions observed were not recent events but had been in existence for some time."[3]

Q. How will PGE incorporate the "lessons learned" in its operations at Coyote?

A. The recommendations from the root cause analysis fall into three categories:

[3] Alstom Metallurgical Report "Steam Turbine Rotor Coupling Examination", Rev. 1

- Plant rotor modification – Alstom removed the section of the LP shaft with the LP coupling, including the cracks and the corrosion pits. This section was replaced with new weld material buildup using submerged arc welding, and a new coupling was machined on the LP rotor shaft. The LP rabbet fit (joint) geometry was modified to reduce stress concentration to improve crack resistance, and care was taken to keep the new coupling free of contaminants prior to assembly. PGE will evaluate the purchase of a spare rotor and will task Alstom with designing a replacement that eliminates the need for a mid-span coupling.
- Monitoring and Testing – Magnetic particle and liquid penetrant inspections were performed on the ST rotor shaft during the initial rotor inspections, but these techniques are not effective unless the cracking is at or very near the surface being tested. Ultrasonic testing was conducted on-site from the ends of the rotor shaft, but did not detect the primary crack because of its orientation parallel to the axis of the rotor.

The coupling cannot be disassembled on-site, which eliminates the possibility of on-site surface examination of the rabbet faces. PGE has asked GE to determine which sections of the mid-span coupling can be effectively inspected on-site (i.e., without disassembling the coupling) for internal cracks using ultrasonic testing (UT) methods. This includes developing the inspection methodology and issuing a service bulletin for Coyote Springs and other plants. At GE's request, part of the cracked mid-span coupling was sent to GE for this effort.

In addition, the mid-span coupling bolt stretch (tightening the nut increases the overall length of the bolt) will be measured during major turbine inspections to determine if any relaxation of the coupling clamping forces has occurred. PGE has also procured an additional vibration monitoring workstation and software to aid in analysis of vibration trends.

- Administration – PGE's chemistry supplier, Nalco, has been enlisted to evaluate the chemistry program to determine if there are procedural improvements that would reduce the possibility of contamination, both during plant operation and during periodic ST inspections.

3. Colstrip

Q. What is PGE's interest in Colstrip?

A. PGE owns a 20 percent share of Colstrip Units 3 and 4. These are coal-fired plants, operated by PPL Montana, LLC, located near Colstrip, Montana. PGE's share of the net capacity of each plant is 148 megawatts (MW).

Q. Please describe the incident affecting Colstrip Unit 4.

A. On July 1, 2013, the plant tripped off-line due to an electrical fault in the generator. Inspection of the unit found significant damage to the generator stator core. The fault occurred in the core laminations. This caused significant damage to the core and also allowed a large amount of molten metal to be blown throughout the generator internals. Because, the damage was too great to repair, the generator had to be completely disassembled and rebuilt with all new core laminations and windings. The generator rotor was also damaged and was shipped to Siemens for a rebuild.

Q. What is the current status of the repair work?

A. The generator and rotor rebuild have been completed and Colstrip Unit 4 returned to full capacity operation on January 24, 2014.

Q. Has PPL performed a root cause analysis of the outage?

A. Yes. The failure root cause analysis (RCA) determined a "most probable root cause." The cause of the failure was most likely inadequate insulation allowing shorting between the core laminations. The inadequate insulation was likely caused during the prior outage. This created enough heating after startup from the prior outage to melt the core in a localized area. This melting was then cooled, resulting in minute particles of solidified iron capable of penetrating adjacent areas. The initial melting resulted in other areas of melting that continued until the plant tripped off-line due to electrical fault in the generator.

The RCA found that PPL Montana conducted all work during the preceding planned outage according to standard industry practices. PPL Montana also hired the original equipment manufacturer, Siemens, to perform the generator maintenance and testing to insure the generator was reassembled correctly after the planned outage. The RCA also found that there was no indication of mis-operation and the unit had adequate relay protection.

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. We recognize that plant availability and performance are key to our ability to serve customers. As a result, we have designed on-going employee training and management initiatives to improve workforce effectiveness and promote a safer working environment. To accomplish our performance and safety goals, we are continuing with our Generation Excellence initiative which includes our Reliability and Maintenance Excellence (R&ME) effort.

Q. What is Generation Excellence?

A. The Generation Excellence initiative, established in 2006, primarily focuses on improvement efforts in the areas of employee safety, employee performance, work process improvement, and plant reliability. 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 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.

At a high-level, PGE's approach to Generation Excellence has been to

- Make culture changes that improve employee safety and performance, such as additional and more rigorous training;

- Develop maintenance programs that better address the criticality of the underlying equipment and use predictive techniques to prevent problems; and,
- Support the integration of Maximo to improve and systematize PGE's maintenance work and workforce management.

Q. Please summarize the status of employee safety initiatives at PGE generation plants.

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 identifies and implements best practices, promotes an environment that minimizes employee safety and health hazards, and increases communication between workers and management.

B. Plant O&M

Q. Please summarize PGE's Production O&M expenses for the 2014 budget and the 2015 test year.

A. Table 1 below summarizes this information:

Table 1
Production O&M Summary
($000s)*

Operating Area	2014 Budget	2015 Test Year
Coal-fired Plants	46,550	44,781
Gas-fired Plants	27,985	31,443
Hydro Plants	15,887	16,802
Biglow Canyon	17,638	17,995
General & Miscellaneous	15,075	15,420
Generation Sub-Total	123,135	126,440
Information Technology (IT) Expenses	7,771	10,011
Total	**$ 130,906**	**$ 136,451**

**Amounts exclude PW2, Tucannon, Sunway III, and Trojan entities*

IT related Expenses are discussed in PGE Exhibit 700.

Q. Why is PGE comparing the 2015 test year costs to the 2014 budget?

A. As discussed in PGE Exhibit 300, the 2014 budget approximates the final UE 262/266 costs that are currently in PGE's retail rates, as approved by Commission Order No. 13-459. PGE's 2014 budget was then escalated to 2015 and updated for incremental costs. We perform these comparisons because this rate case test year is only one year beyond that of UE 262, which had a 2014 test year.

Q. What are the changes in non-labor production O&M expenses between 2014 and 2015?

A. The changes in non-labor plant O&M expenses from 2014 to 2015 are summarized in Table 2 below. PGE labor-related expenses are discussed in PGE Exhibit 600.

Table 2
Production Non-Labor O&M Changes - 2014 Budget to 2015 Test Year
($millions)*

Operating Area	Delta
Coal-fired Plants	(2.30)
Gas-fired Plants	2.66
Hydro Plants	0.50
Biglow Canyon	0.31
General & Miscellaneous	(0.48)
Generation Sub-Totals	0.70
IT Expenses	1.78
Total	**$2.48**

* *Amounts exclude PW2, Tucannon, Sunway III, and Trojan entities*

Q. What are the main drivers for the changes in non-labor plant-related production O&M expenses presented in Table 2?

A. The main drivers of the changes in plant-related non-labor production O&M expenses between 2014 and 2015 are:

- The decline in O&M expense for coal-fired plants is primarily a result of the Colstrip maintenance cycle. Unit 3 is scheduled for a maintenance outage in 2014 while no Colstrip maintenance outages are scheduled for 2015.
- The increase in O&M expense for gas-fired plants is a result of required maintenance, including a major steam turbine inspection at Beaver and a combustion turbine generator inspection at Port Westward 1;
- The increase in O&M expense for the hydro plants corresponds to maintenance work at the Faraday Westside Hydro Project and associated support from the Power Supply Engineering Services (PSES) department.

C. Full Time Equivalent Employees

Q. What is the change in production Full Time Equivalent Employees from 2014 to 2015?

A. The adjusted Full Time Equivalent Employee (FTE) count in PGE's production departments is essentially flat from 2014 to 2015. Table 3 below summarizes the FTE counts for 2014 and 2015. The 2014 and 2015 FTE counts for coal-fired plants reflect PGE's 80 percent ownership share in Boardman in these years.

Table 3
Production FTE Summary*

Operating Area	2014 Budget	2015 Test Year
Coal-fired Plants	95	95
Gas-fired Plants	92	92
Hydro-related	101	101
Biglow Canyon	8	8
PSES	80	82
Environmental	38	36
Other	98	108
PGE Adjustment	**(11)**	**(18)**
Total FTE	**501**	**503**

* *Amounts exclude PW2 and Tucannon*

Q. Does PGE make adjustments to the budgeted FTE amounts 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). The negative adjustment for 2015 also includes Carty project FTEs that are exclusively in Construction Work in Progress (CWIP) and not part of the test year revenue requirement. For PGE's generation departments, these adjustments result in a reduction of 11 FTEs in 2014 and 18 FTEs in the test year. The process for budgeting and adjusting FTEs is discussed in detail in PGE Exhibit 600.

Q. Please explain the Power Supply Engineering Services position additions.

A. PSES provides administrative support, civil, electrical, and mechanical engineering services (including NDE, root cause analysis, and RCM activities) to PGE's generating plants and related departments. The two additional positions are an electrical engineer and an electrical designer who will support the new generation facilities coming online.

Q. Please explain the FTE increase in Other.

A. The increase in Other is the net result of the Carty incremental FTEs, one additional FTE for PGE's Pelton and Round Butte operations, and an additional FTE in the Customer Specialized Programs department. As stated above, the Carty FTEs are removed in the PGE adjustment because they are exclusively included in CWIP and are not included in the revenue requirement in this case. The FTE for PGE's Pelton and Round Butte plants is an additional operations support position. Customer Specialized Programs provides services relating to Dispatchable Standby Generation (DSG), Solar initiatives (e.g., Baldock and Sunway), and Renewable Energy Certificates reporting. The additional FTE is a project manager who will be responsible for DSG resources projects.

D. Thermal Plant Operations and Maintenance

1. 2015 Maintenance Activities

Q. What are the major maintenance activities at PGE's thermal plants in 2015?

A. As indicated above, the major maintenance activities taking place for 2015 are a steam turbine (ST) inspection at Beaver and a combustion turbine generator (CTG) inspection at Port Westward 1.

Q. What are the requirements for the Beaver steam turbine inspection?

A. The Beaver plant has six combustion turbines (CTs) (Units 1–6) and one ST (Unit 7). Beaver Unit 8 is a stand-alone 25 MW simple-cycle CT. 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 ST. Approximately $2.0 million in maintenance and engineering services related to the ST inspection is expected in 2015.

Q. How is the inspection interval determined?

A. Inspection intervals are provided by the manufacturer and may be adjusted based on the service history of the machine. For Beaver, the inspection interval for the ST is 50,000 equivalent operating hours (EOH). EOH are calculated using number of starts, type of starts, operating hours, and other factors. Depending on Beaver's actual operation, PGE generally schedules ST major inspections on a calendar year basis before reaching 50,000 EOH.

Q. Please describe the major Port Westward 1 maintenance work taking place in 2015.

A. Port Westward 1 has scheduled a CTG major inspection in 2015 based on EOH. This inspection represents approximately $0.9 million of Port Westward 1's O&M budget in 2015.

Q. Why must this inspection take place in 2015?

A. The manufacturer, Mitsubishi, states in its Operations and Maintenance Manual that the first major inspection for the CTG must be conducted either six years after installation or upon reaching 48,000 hours of operation. In 2015, the plant will be eight years old and is expected to have over 51,000 hours of operation. Delaying the inspections to 2016 (9 years and approximately 58,000 hours) is considered high-risk based on our current rate of degradation of turbine performance. Consequently, the inspection is scheduled for 2015, based on current projections of operational hours.

Q. Does PGE expect long-term service agreement costs at Port Westward 1 to increase in 2015?

A. Not materially. The long-term service agreement (LTSA) at Port Westward 1 covers regular inspection and maintenance of the plant's CT. 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). The level of dispatch realized by the plant is directly correlated to the LTSA costs. PGE's 2015 budget reflects a "normal" level of operation and the associated LTSA costs. The increase in 2015 relative to 2014 is largely due to a CPI-based escalation factor. PGE recovers the costs associated with the LTSA in the Port Westward 1 major maintenance accrual approved in UE 262. The forecast used to develop the amortization amount set in UE 262 accounts for the CPI-based escalation factor component of the LTSA costs.

Q. Is PGE proposing to include the costs of the CTG inspection in the major maintenance accrual established in UE 262 for the LTSA expenses at Port Westward 1?

A. Yes. In UE 262, PGE proposed, and the Commission approved, a major maintenance accrual based on a projection of LTSA expenses plus expenses related to the steam turbine and steam turbine generator inspection scheduled for 2014. For the CTG inspection in 2015, we propose to increase the annual amortization amount set in UE 262 by approximately $0.17 million to collect the projected CTG inspection expenses over a period of five years.

Q. Does PGE propose any other changes to the annual amortization amount for the Port Westward 1 major maintenance accrual?

A. Only for the CTG inspection as noted above. The amortization for the major maintenance accrual already accounts for the inflationary component of LTSA costs and PGE has no additional major inspections planned for 2015, other than the CTG inspection.

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 an 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 expenses, however, are outside the scope of NVPC, and are generally only recoverable in a GRC proceeding.

2. Boardman Biomass Project

Q. What is PGE's Boardman Biomass Project?

A. The Boardman plant is currently fueled with coal and is scheduled to cease operation as a coal plant by the end of 2020. PGE is exploring the possibility of repowering the Boardman plant with biomass as its fuel source.

Q. PGE Exhibit 500 (NVPC) describes costs associated with the biomass project at Boardman. Are the costs related to this project included in the 2015 O&M budget presented in this case?

A. No. The costs associated with the biomass project and the 100 percent test burn at Boardman are fully-contained within the costs in PGE's 2015 NVPC forecast presented in PGE Exhibit 500.

Q. Why are the costs associated with the biomass project and 100 percent test burn at Boardman presented as part of PGE's NVPC forecast, rather than in the O&M budget?

A. The costs of growing, procuring, and torrefying biomass will be accounted for by PGE as fuel inventory. (Torrefying is the "roasting" process that turns green biomass into a charred material that can be used as fuel.) This fuel inventory will be expensed as a fuel cost when the 100 percent test burn takes place. For these reasons, as well as the need to estimate the value of energy produced during the 100 percent test burn, PGE includes the costs (and benefits) of the biomass project in the NVPC forecast, rather than in O&M expense. A detailed discussion of the biomass project at Boardman is presented in PGE Exhibit 500.

IV. Energy Imbalance Markets

Q. What is energy imbalance?

A. A balance between generation and consumption must be maintained by a Balancing Authority (BA) within certain bounds at all times in order for the BA to maintain system stability and meet its reliability requirements. Generation from plant operation and contracts is scheduled in advance to match expected energy consumption. In real time, pre-scheduled generation will not match actual energy consumption exactly. System operators must correct for this "imbalance" between pre-scheduled generation and realized electricity consumption.

Q. What is an Energy Imbalance Market (EIM)?

A. EIM is the standard industry term for a market mechanism that corrects energy imbalances via a centralized dispatch system across a given market footprint. EIM employs a Security Constrained Economic Dispatch (SCED) tool to deliver the lowest-cost, most reliable energy solution for the market footprint. During sub-hourly intervals, SCED determines a least-cost re-dispatch of available generation resources that matches generation and load. This re-dispatch results in an efficient matching of available resources and loads subject to physical power flow and transmission constraints.

Individual market designs will differ in their scope, their market and operational requirements, and the associated agreements between market participants. These associated market protocols are tailored to each region to ensure a well-functioning market that meets with regulatory imperatives at the local, state, regional, and federal levels.

An EIM is not a Regional Transmission Organization (RTO), an Independent System Operator (ISO), or an organized market for the procurement of long-term capacity rights. Further, in the Western Interconnect, an EIM would not be a replacement for the current structure of bilateral energy trading and BA obligations and management, but would instead serve as a discrete additional market mechanism to help meet individual entities' balancing needs at least-cost.

Q. Why is an EIM being considered for the Northwest Power Pool footprint?

A. The Northwest Power Pool Members Market Assessment and Coordination Committee (NWPP MC) Initiative was launched in March 2012 to investigate, among other goals, ways to manage renewables integration and transmission system operations more efficiently. Since that time, the NWPP MC Initiative has progressed through two phases, both of which sought to clarify potential quantitative and qualitative benefits of EIM for the NWPP members' geographic footprint, as well as any associated bilateral market impacts or opportunities. The NWPP MC studies were undertaken in response to previous West-wide studies, which had indicated that an EIM, modeled after the market platform and protocols used by the Southwest Power Pool, offered significant potential cost savings for the region. Those savings were expected to come from increased dispatch efficiency of the regions' generating resources, reduced curtailment of transmission schedules in real time, and reduction in total balancing reserves. The NWPP MC studies supported many of these findings, albeit with different outcomes in terms of scale and certainty. Work in these initial phases also investigated the extent to which regional infrastructure capabilities must be improved to allow members to attain these benefits.

While most NWPP MC members were encouraged by the initial positive outcomes of these studies, as a whole, the members agreed more work was needed to fully understand if and how an EIM could be implemented effectively across the NWPP footprint to achieve greatest reliability and economic benefit at least-cost and with least-risk to NWPP MC members. The NWPP MC has approved the funding of a Phase 3 for 2014. Phase 3 will continue this scoping from a market design perspective and begin implementing the infrastructure and bilateral energy market enhancements necessary to create the option to install an EIM across its footprint.

Q. How does an EIM operate?

A. In general, an EIM facilitates sub-hourly optimization of load-resource balancing across a wide-area footprint. The EIM market operator receives load-resource plans from each market participant for each market scheduling interval. Along with this load-resource plan, each participant also submits the dispatchable range and associated price curve for each resource it can make available to the market operator for dispatch within each market interval. Using this information, the market operator re-dispatches the resources made available to it while respecting available transmission flows and individual resource economics. Whenever possible, the market operator will net over- and under-generation and over- and under-consumption at the load level, to take advantage of wide-area load and generation diversity across the market footprint.

It is important to note that each individual entity must be able to meet its load-resource needs independently of the market for each market interval, and cannot depend exclusively on the resources made available to the EIM to meet its needs. Further, each entity retains its responsibility for maintaining its load-resource balance within each five minute dispatch period (known as its Regulation and Frequency Response) and for complying with all applicable North American Electric Reliability Corporation (NERC) standards.

Q. What EIM options are available to PGE?

A. Currently, there are two EIM options under development in the Western Interconnect. One option is the EIM being developed for initial deployment between California ISO (CAISO) and PacifiCorp (PAC) in late 2014. Another option is the market development initiative of the NWPP MC, which has outlined a potential path to an EIM for its members, but has not agreed to fund additional phases, which would be required for the startup of a market, beyond Phase 3 at this time.

Q. Is it reasonable for PGE to implement an EIM without other participants?

A. No. The inherent value of an EIM lies in its ability to share load and generation diversity, and to more efficiently manage resources around transmission constraints, across a wide-area footprint with multiple participants. Absent a wide-area footprint or significant BA to BA sub-hourly transfer mechanisms, the benefits of a tightly constrained EIM are unlikely to outweigh the costs due to the lack of diversity.

PGE currently performs a SCED within our metered BA boundary, optimizing our generation dispatch to maintain load-resource balance in real time without violating transmission limits or other constraints. PGE is expanding its capabilities and operational efficiency in this area through its Dynamic Dispatch Program, the completion of which will prepare PGE to realize the wide-area footprint benefits of an EIM in the future if an appropriate market opportunity arises.

Q. What is the current status of PGE's EIM planning?

A. PGE has been an active participant in the developmental processes of both the CAISO-PAC effort and the NWPP MC since their inceptions. PGE is committed to exploring options that will allow us to meet our load service imperatives for our customers, such as reliability, at least-cost.

PGE is primarily committing its resources and support to the NWPP MC effort in 2014. The work being done by the NWPP MC has broad-based benefits to the region in terms of reliability and efficiency regardless of particular future organized market solutions that may follow. As part of the NWPP MC effort in 2014, PGE will have the opportunity to participate in the EIM design efforts and the development of market operator and platform requests for proposals, as well as assist in the development of a governance structure for a proposed market. Following these developments, the NWPP MC members, including PGE, are likely to vote on proceeding with a NWPP MC designed EIM in late 2014.

During this time, PGE will continue to evaluate the CAISO EIM proposal. This will include an assessment of

- The benefits it may offer to PGE's customers;
- Operational challenges and opportunities presented by the CAISO EIM design;
- Workings of their governance structure;
- Potential impacts to existing bilateral market activity; and,
- Overall costs of implementation.

PGE is committed to achieving the benefits of an EIM and will monitor and participate in both development processes.

Q. Are there 2015 test year costs associated with PGE's EIM implementation and participation?

A. Yes. There will be costs common to both EIM efforts and PGE expects to incur these costs regardless of which EIM initiative we choose to participate in. Either EIM option will require initial investment from participants during the beginning of 2015. We propose to capitalize PGE's initial investment of $1.5 million and amortize this amount over a five-year period.

Q. What benefits to customers does PGE anticipate that participation in an EIM will provide?

A. PGE currently manages imbalance within our Balancing Authority Area (BAA) on a stand-alone basis. PGE is responsible for maintaining frequency within our metered boundary according to NERC reliability standards. This is accomplished through a combination of deploying our own resources and resources available to us in response to within-hour deviations in load or generation. Through an EIM, PGE would be able to take advantage of regional load and resource diversity. For example, when PGE experiences a positive load excursion, another entity may at the same time be experiencing a negative load excursion that the market operator could net across the two systems, resulting in less deployment of resources by both entities.

PGE would also expect to see a reduction in deployment costs when simple diversity is not adequate to balance the system. Thus, instead of PGE dispatching resources available to it to meet its imbalance, the market operator could dispatch another entity's resource to meet the imbalance, if such a resource had been made available to the market and is a lower-cost resource than those available to PGE. Therefore, the primary economic benefits of EIM accrue due to the potential for reduced costs of energy dispatched within the hour and increased economic sales of otherwise uncommitted resources that PGE makes available to the EIM within the hour.

It is important to note that a key prerequisite to the formation of EIM is Resource Sufficiency. This is the requirement that all market participants bring sufficient balancing capacity to the EIM to meet their stand-alone needs, a requirement that strengthens the reliability of the EIM and ensures equitable treatment among participants. As a result, PGE's balancing capacity needs remain the same with or without an EIM.

Further, it is important to note that neither PGE's long-term energy or transmission capacity needs, nor our bilateral market transactions, are materially affected by the presence of a discrete, within-hour EIM under either potential market option (NWPP MC or CAISO EIM).

PGE cannot assess fully the impacts to net variable power costs at this time. PGE expects to have greater certainty in that area as market designs are completed and market participation and footprint decisions are made in late 2014. Further refinements will be possible once the SCED tool has been developed and tested prior to market implementation.

Q. How is PGE managing the costs associated with participating in an EIM?

A. To date, PGE has been managing the costs associated with tracking and participating in the formative stages of both market coordination efforts through the efficient deployment of existing FTEs. However, as these efforts move into implementation phases, additional resources will be required in multiple working groups within the company. PGE is committed to integrating our EIM-related activities with other projects and views potential EIM solutions as one piece of a broad strategy for reducing customer costs and increasing operational reliability over the coming years.

Q. Will PGE provide updates regarding its EIM process?

A. Yes. As needed throughout the rate case process, PGE will provide updates through workshops with interested parties.

V. Power Resources Cooperative

Q. Please describe Power Resources Cooperative (PRC) and its relationship to the Boardman Coal Plant.

A. PRC is an Oregon cooperative corporation whose members are 13 Northwest retail electric distribution cooperatives. PRC is a 10 percent owner of the Boardman Coal Plant (Boardman) and is a party to the Agreement for Construction, Ownership and Operation of the Number One Boardman Station on Carty Reservoir (the "Boardman Operating Agreement"). The Boardman plant is a 600 MW (gross capacity) coal fired generating facility located near the town of Boardman, Oregon. PGE is the plant operator.

Q. Are there other co-owners besides PRC?

A. Yes. Idaho Power Company (IPC) owns 10 percent and Portland General Electric owns 80 percent of the Boardman plant.

Q. Please summarize PGE's interest in acquiring PRC's ownership share?

A. PGE is interested in acquiring PRC's ownership share for two primary reasons:

- Boardman will cease coal-fired operations by the end of 2020. As PGE begins exploring alternatives for Boardman, including biomass and plant closure, the process will be much simpler and more efficient with a reduced number of co-owners.
- A transaction with PRC will be executed at a price that results in either no harm or a benefit to customers.[4]

Q. Please describe the general parameters of the transaction and its components.

A. The major elements are outlined below.

[4] The transaction price will be based on the most recent information and assumptions regarding market expectations over the remainder of coal-fired operations at Boardman.

- PGE would acquire all of PRC's rights and obligations relating to the 10 percent ownership share of the plant. These include generation, operations and maintenance, and decommissioning liabilities.
- The closing of the transaction will be subject to certain conditions-precedent, including approval by the Oregon Public Utility Commission.
- PRC currently sells its share of the plant output to the Turlock Irrigation District (TID) under a long term purchased power agreement that expires December 31, 2018. This power sales contract will be assigned to PGE.
- PGE will purchase PRC's share of the coal pile and materials and supplies inventory.

Q. Has PGE mitigated potential risks associated with this transaction?

A. Yes. PGE is structuring the transaction so that the price will reflect possible future risks, such as changes to regulations, which may increase the costs associated with the end of coal-fired operations at Boardman. In doing so, PGE is mitigating future risks that could adversely impact customers.

Q. Have PGE and PRC finalized a transaction?

A. No. PGE and PRC are currently discussing the major elements of a transaction to be reflected in a term sheet. We expect to execute definitive agreements with PRC in March 2014 and to close in January 2015.

Q. If an agreement is reached, would PGE update its filing?

A. Yes. PGE will submit supplemental testimony, supporting work papers and an updated revenue requirement by April 1, 2014 to reflect the final terms of the agreement and costs, including NVPC.

Q. Does PRC currently have a contract to sell the plant output to PGE in 2019 and 2020?

A. Yes. In 2011, PRC executed an agreement with PGE to deliver the plant output to PGE's system at the Daily Mid-C ICE Index, On-peak and Off-peak price applied during applicable delivery hours. PRC and PGE will financially settle this agreement in a separate transaction. Executing both this transaction and the 10 percent ownership purchase transaction will ensure that customers receive the full benefit of the 2011 agreement.

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
801	PGE Generating Resource Summary

	PGE's 2015 Generation Resources	Annual Energy (MWa)
	PGE Resources	
Coal	Boardman	331
Coal	Colstrip	270
Gas	Beaver	52
Gas	Beaver 8	0
Gas	Port Westward	275
Gas	Port Westward 2	21
Gas	Coyote Springs	178
Wind	Biglow Canyon	143
Wind	Tucannon	70
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	**1,540**
	Long-term Contracts	
Hydro	Wells	103
Hydro	Wanapum	44
Hydro	Priest Rapids	44
Hydro	Rocky Reach	23
Hydro	Rock Island	11
Hydro	Portland Hydro Project	10
Wind	Other Wind	38
Solar	SunWay Projects	0
Solar	Other Solar Contracts	4
Hydro	Other Hydro Contracts	56
Other	Various Other Contracts (Net)	128
	Long-term Contracts Total	**460**
	Total Resources	**2,000**

Estimated annual average generation assuming average hydro conditions
Energy reflects PGE's share of the resources
Source: M610PUC10-00n-2015 GRC.xlsm

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 283

Transmission & Distribution O&M

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony of

Bill Nicholson
Bruce Carpenter

February 13, 2014

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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 2015 test year Transmission and Distribution (T&D) operations and maintenance (O&M) costs. 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 safe and reliable energy delivery services to our customers;
- Deploy new techniques and process improvements to improve efficiency and increase customer value;
- Cultivate a corporate culture that improves employee safety; and
- Ensure compliance with regulations for transmission grid reliability.

Q. What are your O&M costs for the 2015 test year?

A. In 2015, we forecast T&D O&M costs totaling $109.7 million, which represents a $4.6 million increase compared to the 2014 budget. Table 1, below, summarizes T&D O&M for 2014 and 2015.

Table 1
Summary of T&D O&M Expenses ($ Million)

	2014 Budget	2015 Test Year	Variance 2014 - 2015	Annual Average % Increase
T&D O&M	$86.5	$87.4	**$0.9**	1.0%
Information Technology	$18.5	$22.2	**$3.7**	19.9%
Total T&D O&M*	**$105.1**	**$109.7**	**$4.6**	**4.4%**

**May not sum due to rounding*

Q. Why are you comparing the 2015 forecast to the 2014 budget?

A. We do so because PGE recently completed a general rate case with a 2014 test year budget, in which Commission Order No. 13-459 (issued December 9, 2013) established costs that are currently in retail rates. As noted in PGE Exhibit 300, because we are holding PGE's overall 2014 budget flat to the 2014 authorized costs, comparing the 2015 forecast to the 2014 budget reflects the most relevant cost increases.

Q. What do the Information Technology (IT) costs represent?

A. They represent costs that are directly assigned and allocated to T&D as they relate to PGE's efforts to develop, operate, and maintain our computer, information, cyber, and communication systems. Because IT costs are assigned and allocated to all of PGE's operating areas, IT costs are discussed separately in PGE Exhibit 700.

Q. Why do the IT costs increase by $3.7 million?

A. The IT cost increase is driven by two primary areas:

- IT deferral mechanism, which was created by the stipulation in PGE's previous general rate case (UE 262); and
- Labor loadings on allocated IT O&M, which increase as labor-related costs increase.

Labor loadings and the IT deferral mechanism are discussed in greater detail in PGE Exhibits 600 and 700.

Q. How did the T&D labor force change from 2014 to 2015?

A. From 2014 to 2015, T&D FTEs are projected to decrease by approximately 3.4. This decrease is primarily driven by the T&D Transformation projects described below. The change in FTEs is summarized in Table 2, below.

Table 2
Summary of T&D FTEs

Category	**2014 Budget**	**2015 Test Year**	**Variance 2014 – 2015**
Unadjusted T&D FTEs	966.5	962.6	(3.9)
Labor Adjustment	(16.3)	(15.9)	0.4
Adjusted T&D FTEs*	**950.2**	**946.7**	**(3.4)**

**May not sum due to rounding*

Q. Please explain the labor adjustment.

A. As discussed in PGE Exhibit 600, PGE applied two labor adjustments in its 2015 forecast. The first is a company-wide adjustment of ($5.0) million that reflects an expected 54.3 unfilled FTE positions in the test year forecast. The allocated T&D portion of this adjustment is approximately ($1.4) million and represents 15.9 FTEs in 2015.

Q. What is the second labor adjustment?

A. The second adjustment is ($1.0) million and is related to efficiencies we expect to realize from the myTime project (see also PGE Exhibit 600). The T&D component of this adjustment is ($0.3) million but this adjustment only affects labor costs and not FTEs.

Q. How is your testimony organized?

A. In the next section we discuss PGE's improvement efforts in T&D functions. In Section III, we discuss T&D O&M costs in more detail. Section IV contains our qualifications.

II. Improvements and Efficiency

Q. In PGE's previous general rate case (UE 262) you introduced T&D Transformation, a program focused on improving efficiency and effectiveness. Would you please provide a brief summary of the program?

A. T&D Transformation is a subset of the 2020 Vision Program, wherein PGE is implementing process improvements and replacing a large number of software programs with enterprise applications (see PGE Exhibit 700, Section III). For T&D Transformation, we performed a detailed review of the opportunities for using this new software to implement industry-leading practices across the organization to more effectively capture the benefits of the new tools. As a result, PGE is implementing multiple initiatives to improve efficiency and effectiveness within T&D, with a focus in the following five areas:

- Employee Safety
- Accountability
- Process Standardization
- Productivity
- O&M Efficiency

Q. Please describe how the T&D Transformation program is implemented.

A. The T&D Transformation program is based upon the principles of centralization, standardization and integration processes. Operating units are first centralized and standardized, then technology is integrated where possible to streamline workflow and automate processes.

Q. What process improvements are you projecting to complete in 2014?

A. PGE plans to complete the following process improvements by year-end 2014:

- Consolidation of regional line dispatch: Consolidates all regional dispatchers (Southern, Western and Eastern) from five locations into one to improve resource sharing.
- Centralization of service coordination: Consolidates service coordinators and customer contact functions for the Tree-Trimming and Power Quality groups into a single location at the Tualatin Contact Center (TCC) to improve customer response time and standardizes practices.
- Supervisor in the Field: Increases the time a General Foremen (GF) spends on jobsites with field crews for both safety and work practice consistency.
- Off-Shift Crews: Creates crews that are available during evenings and throughout the weekend to improve customer response time and reduce overtime expenses.
- Fleet optimization: Finds the right combination of new, repurposed and rented assets to support PGE's operational needs.
- Other Field Improvements: Includes cost savings from a number of projects that focus on improving employee safety and efficiency, such as Safe and Efficient Design Construction (SEDC) projects, Design and Engineering Centralization, and Substation Shutdown Planning Improvement.

Q. What technologies are you implementing to which T&D Transformation can be applied?

A. As part of the 2020 Vision program, the first phase of technology (Maximo, Mobile & Scheduling Wave 1, completed in late 2012) benefited Substation Operations, most T&D single field employees, generation, and associated office support through software implementation that included:

- 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 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 (Maximo, Mobile & Scheduling Wave 2) will deploy these same tools to other employee groups within T&D such as asset management, engineering design, joint-use and line crew employees. The second phase is expected to be deployed in late 2014.

Q. What are the expected benefits of the new implemented technology?

A. Maximo, Mobile & Scheduling will improve employee safety, heighten accountability, and standardize our processes, which will improve productivity and efficiency as follows:

- <u>Employee Safety:</u> With mobile devices in the hands of field workers, PGE is able to track work processes being performed and logged when a worker is completing an inspection or doing maintenance work in real-time. The Mobile & Scheduling tools improve employee safety by providing PGE with real-time updates on the location of our field workers and provide a communication link in the field.
- <u>Accountability:</u> Maximo, Mobile & Scheduling provides teams with better information. 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: Productivity should increase as work orders are created in Maximo, routed to the closest available resource with the correct skillset, and dispatched to the field workers (including contractors) electronically. The new technology provides workers with real-time customer and asset information. Mobile & Scheduling tools provide:
    - Optimization of scheduling to reduce travel time and crew costs;
    - An opportunity to re-optimize work schedules dynamically as needed;
    - Real-time dispatching of work details and status updates; and
    - Automatic asset information updates and work order closure.
- Efficiency: Maximo provides PGE with the ability to track inventory use to find optimal 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. In UE 262, you projected annual O&M savings of $3.4 million through 2014 from these programs. Has PGE updated this estimate since then?

A. Yes. Through the T&D Transformation process improvements, we project annual O&M savings of $3.3 million through 2014. Moreover, we expect an additional $0.8 million in T&D O&M savings through 2014, mainly attributable to PGE's Lean process review and functional reorganization. In total, PGE's projection for T&D O&M savings through 2014 is approximately $4.1 million. PGE Exhibit 707 provides more detail on projected T&D O&M savings.

Q. What is the Lean process?

A. Lean is an 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. Are any major new technologies and/or systems being implemented in the 2015 test year?

A. Yes. In mid-2015, PGE plans to complete the remaining T&D projects under the 2020 Vision Program, which consist of:

- Geospatial Information System and Graphic Work Design Applications (GIS/GWD) Replacement; and
- Outage Management System (OMS) Replacement Program.

Q. Please describe the GIS/GWD and OMS Replacements.

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.

Q. What are the expected improvements from the new GIS/GWD tools?

A. The new GIS and GWD will improve customer service, reliability, safety, and eliminate manual/paper-based work processes, which will improve efficiency. Some specific expected improvements are:

Customer Service

- Shorter wait time between customer requests and completion of design work.
- Faster outage diagnosis and response.
- Better response to service calls.

Reliability

- Better data to help asset management develop long-term strategies for preserving and replacing assets.
- Quicker diagnosis to help reduce the length of service interruptions.
- Ability to see risks before they cause interruptions.

Safety

- Better data to help keep facilities in safe condition and identify threats before they become hazards.
- Potential to bring in updates from first responders, and other sources in an emergency.

Efficiency

- Quicker, more accurate updates to the network after completion of work.
- Better diagnostics in the field.
- Improved data accuracy and completeness.
- Integration between office and field, eliminating data backlogs and errors.
- Virtual work packets replace paper documents that can be damaged.

- Ability to see where work is planned or in progress.

Q. What are the expected improvements from the new OMS application?

A. The new application will make use of real-time operational data to proactively alert PGE, its customers, and other stakeholders of outage information, improve real-time information before and during outages. In addition, the new OMS application will integrate with PGE's Automated Vehicle Locating system and smart meters to efficiently dispatch crews and improve outage response time.

Q. Do you forecast any efficiencies from these projects in 2015?

A. Not during 2015. As mentioned above, the new GIS/GWD system and OMS application are expected to be operational in mid-2015. Once the new systems are in place, employees will receive formal training and adapt to the new systems. When the systems are implemented, T&D operations will be reevaluated and new process improvements will be developed. The improvement process is an ongoing multi-year effort. Significant incremental savings should not be expected each year. We are striving for overall cumulative savings, and will continue our effort for continuous improvement.

Q. Do you forecast efficiency savings in the 2015 test year from other sources?

A. Yes. At this time, we forecast additional annual O&M savings of approximately $0.3 million in 2015, mainly attributable to Fleet Optimization and Lean improvements.

Q. What are the projected cumulative savings for T&D through the 2015 test year?

A. As we stated above, the new projection for 2014 O&M savings is approximately $4.1 million, which is greater than the original estimate in UE 262. The additional savings expected in 2015 bring T&D's projected cumulative savings to approximately $4.4 million through the 2015 test year.

Q. Are the O&M savings discussed above reflected in PGE's 2015 test year forecast?

A. Yes. PGE Exhibit 707 provides more detail on T&D efficiencies.

III. Transmission & Distribution Operations

A. O&M Expenses

Q. In Section I, you stated that T&D O&M expenses have increased by approximately $0.9 million from 2014 budget to the 2015 forecast. What are the components of that increase?

A. The following table identifies the major components that account for the forecasted $0.9 million increase:

Table 3
Summary of T&D O&M Expenses ($ Million)

Category	2014 Budget	2015 Test Year	Variance 2014 - 2015	Annual Average % Increase
Labor	$ 37.4	$ 38.9	$ 1.5	4.1%
Non-Labor	$ 49.1	$ 48.5	($ 0.6)	(1.3%)
Total T&D (not including IT)	**$ 86.5**	**$ 87.4**	**$ 0.9**	**1.0%**

Q. What accounts for the $1.5 million increase in T&D labor O&M expenses?

A. The T&D labor O&M increase is driven primarily by cost escalations which are discussed in greater detail in PGE Exhibit 600.

Q. Do any major capital projects close to plant in the 2015 test year?

A. Yes. In 2015, construction of the Shute Substation will be completed. This substation provides distribution capacity needed to support growth in the region.

Q. Did PGE include amounts associated with Shute Substation in its 2015 rate base for calculating the test year revenue requirement?

A. No. As noted in PGE Exhibit 300, Section VI, PGE's test year rate base is set at the December 31, 2014 level, and does not include 2015 additions to plant.

Q. Did you include any other costs associated with these projects in the 2015 forecast?

A. Yes. Because this project will be providing benefit to customers for most of 2015, we include partial year depreciation of approximately $0.6 million.

B. 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. PGE's SQM reports provide 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?

A. Yes. As shown in Table 4 below, for 2011 through 2013, PGE's results were well within the thresholds established by the OPUC. PGE's three-year weighted averages (2011 through 2013) for all three measures also fall well below the OPUC penalty thresholds.

Table 4
Three-year Weighted Averages and Penalty Threshold Limits

Year	SAIDI (minutes)	SAIFI (occurrences)	MAIFI (occurrences)
2013	62	0.5	0.9
2012	72	0.6	1.1
2011	66	0.5	0.9
3-Year Weighted Average	**66**	**0.5**	**1.0**
OPUC Level 1 Penalty Threshold	105	1.2	5.0

C. Conclusion

Q. Please summarize your request for T&D in this filing.

A. We request that the Commission approve PGE's forecast of $109.7 million in T&D costs in the 2015 test year. Not including the $22.2 million in IT costs, which are discussed in detail in PGE Exhibit 700, this represents a $0.9 million increase from the 2014 budget and is primarily driven by a $1.5 million increase attributable to labor escalation, which is discussed in PGE Exhibit 600.

Absent the above-referenced cost increases, PGE has held its 2015 T&D forecast essentially flat. To mitigate cost increases, we continue to: 1) implement T&D Transformation to develop and apply process improvements that are necessary to achieve greater system benefits from the software and hardware implementation projects, and 2) employ benchmarking tools to identify additional areas of improvement.

IV. 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.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 283

Customer Service

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Kristin Stathis
Carol Dillin

February 13, 2014

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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 VI of our testimony.

Q. What is the purpose of your testimony?

A. We explain Customer Service O&M costs for the 2015 test year.[1] We also discuss various improvement initiatives that are either completed or in progress and support our commitment to improve efficiency, achieve operational effectiveness, and enhance Customer Service offerings. Targeted improvements will ensure we meet growing customer expectations including the way we use technology to serve them and the self-service options we offer.

Q. How is your testimony organized?

A. We begin with a cost overview of PGE's Customer Service organization. As part of that overview, we discuss the Customer Service deferral mechanism for 2015. We discuss what PGE has accomplished and what PGE plans to achieve in the near term. PGE Exhibit 1001 provides a summary of Customer Engagement Transformation (CET) program forecasted O&M. In Section III, we discuss improvement initiatives outside the CET program as well as provide an update on CET projects, past and present. Also in Section IV, we discuss an update on the implementation of PGE's fee-free bankcard program and costs in 2015. We conclude with our qualifications in section VI.

[1] Calculated Customer Expenses are consistent with FERC Chart of Accounts categories Customer Accounts Expenses and Customer Service and Informational Expenses (901-910).

II. Customer Service Organization Cost Overview

Q. What is PGE's goal for the Customer Service organization?

A. PGE's goal for the Customer Service organization is to deliver value to our customers by providing excellent service at a reasonable price. PGE achieves this goal through operational excellence that incorporates improvement efforts and efficiency, and by responding to the needs and expectations of our customers through enhanced customer service offerings.

Q. Please describe PGE's Customer Service organization functions.

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: contact center, community offices, self-service[2] customer channels[3] such as the web, mobile and Interactive Voice Response (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 then developing and delivering products and services that best meet their needs.

Q. What are PGE's forecasted Customer Service costs in 2015?

A. PGE forecasts approximately $78.7 million in Customer Service costs for 2015, with the increase, relative to PGE's 2014 budget, driven primarily by labor increases that are partially

[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. Web, text, 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.

offset by decreases in non-labor and the effects of UE 262 for CET. Table 1 below summarizes the costs.

Table 1
Customer Service O&M Expenses ($Millions) and FTEs

Category	2014 Budget	2015 Forecast	Variance
Labor	$31.3	$32.7	$1.4
Non-Labor	22.5	21.1	(1.3)
Uncollectibles	8.3	9.2	0.9
Subtotal*	**62.1**	**63.0**	**0.9**
IT Costs	14.4	18.1	3.7
CET Deferral & Amortization	(6.4)	(2.4)	4.0
Total Costs*	**$70.2**	**$78.7**	**$8.6**
FTEs	**506.1**	**506.3**	**0.2**

* Numbers may not sum due to rounding

Q. Please summarize the increase in Customer Service costs from 2014 to 2015.

A. Customer Service O&M expenses increased from $70.2 million to $78.7 million, or by $8.6 million. However, after removing the effects of the 2014-2015 CET deferrals and IT costs, O&M expenses increase by approximately $0.9 million. Following are details on the differences in Customer Service costs:

- Labor costs are projected to increase by $1.4 million primarily due to increases in wage and salaries. The slight increase beyond base escalation is driven primarily by the increased need for temporary labor to support and complete CET initiatives.
- Non-labor O&M expenses decreased by approximately $ 1.3 million primarily due to a transition from O&M activities to capital activities in 2015 compared to 2014 within the CET program. This decrease is partially offset by an increase in the

fee-free bankcard program of $1.3 million for 2015 compared to 2014, and is discussed further in Section A

- IT costs increase by approximately $3.7 million. Related IT costs are described in detail in PGE Exhibit 700.

Q. Please provide some background and detail related to the CET deferral mechanism.

A. In a UE 262 stipulation, PGE agreed to treat 2014 CET O&M expense as a regulatory asset, amortizing the amount over five years (i.e., 2014 - 2018), which was approved in Order No. 13-459. As a result, approximately $6.4 million is removed from CET O&M expense for 2014.

Q. Does PGE use the same methodology used for 2015 CET O&M costs?

A. Yes. Because the CET program is scheduled to be complete in 2018, PGE has applied this same methodology to the total 2015 CET O&M costs amortized over four years (i.e., 2015-2018). The effect reduces the CET O&M expense by approximately $4.0 million for 2015. With the $1.6 million of 2014 CET amortization costs added to 2015, the net reduction is approximately $2.4 million.

III. Improvement Initiatives

Q. Briefly provide an update on improvement initiatives mentioned in UE 262 that PGE has implemented outside the Customer Engagement Transformation (CET) program.

A. PGE has implemented projects that improve service, increase efficiency, and provide benefits and convenience to customers in how they interact with PGE, increasing value for customers and strengthening our customers' level of satisfaction. PGE monitors customer satisfaction levels by participating in ongoing market studies conducted by Market Strategies International (MSI) and JD Power and Associates. PGE Exhibits 1002 contains 2013 satisfaction results as presented by MSI for 4th quarter for residential and general business customers, and JD Power and Associates for 2013 Electric Utility Residential and Business Customer Satisfaction Study results.

Following is an update on Customer Service improvement initiatives mentioned in UE 262 and completed in 2013:

- <u>Mobile Alerts for Property Managers</u>: Property managers may enroll to receive alerts when tenants "start" or "stop" electric service. The program launched November 25, 2013, with a promotional campaign planned in 2014.
- <u>Enhanced Energy Tracker</u>: PGE's enhanced version of the 'Energy Tracker' web application was launched November 25, 2013 on PortlandGeneral.com. Customers may now enroll to receive a proactive email estimating their projected monthly bill based on their usage to date. In addition, customers may also enroll to receive an alert when their projected monthly bill is estimated to exceed a threshold amount they have specified. Both options enable customers to manage their usage and overall bill amount. Promotional campaigns are planned in 2014.

- Automated Payment Extension Option: Customers with accounts up to 30-days past due may use PGE's self-service payment extension option available on the IVR and Web. Customers can request a payment extension without the need to talk to a Customer Service Representative. In the future, PGE plans to launch Phase II of the Automated Payment Extension Option, expanding the program and its functionality to customers whose accounts are 30-days or more past due.
- 'Start' and 'Stop' Service Requests: PGE reduced the time required to process 'start' and 'stop' service requests by automating back-end office processing.

Q. The project implementation dates of some initiatives mentioned in UE 262 were moved from 2013, with one project likely to be delayed past 2014. Please explain.

A. In 2013, one project took longer than expected to complete. As a result, PGE adjusted three project timelines.

The following two projects were moved to 2014:

- Improve the paperless billing program to include improved e-mail notifications and easy access to information, such as newsletters, for paperless bill customers.
- Reduce the time required to process "move" service requests via the web by automating the resulting manual process.

Due to ongoing project prioritization, the third project will be prioritized to an unknown future date:

- Eliminate the need for customers to call PGE with a confirmation number after making payments to avoid disconnection.

In 2015, projects will focus primarily on CET work discussed in the next section. Other improvement initiatives will be considered on a case-by-case basis and prioritized against the overall CET effort.

IV. Customer Engagement Transformation (CET) Update

Q. In PGE's previous general rate case (UE 262), you introduced the Customer Engagement Transformation (CET) Program focused on efficiency and effectiveness and delivering the long-term strategy for how PGE can enhance its Customer Service offerings. Please provide a brief summary of the 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). CET was discussed in detail in our last general rate case (UE 262, PGE Exhibit 900, Section III).

Q. Please describe 2013 activities related to CET that have been implemented.

A. PGE has implemented projects using existing staff and resources to improve service and increase efficiency through standardization of practices and processes. Following are examples of what we have accomplished:

- Across the entire Customer Service Operations (CSO) organization:
  - PGE created a standardized employee coaching process to increase individual employee performance and provide foundational support throughout the multi-year CET program. In 2013, lead representatives conducted over 1,500 coaching sessions with their employees.
- At the Customer Service Contact Center:
  - PGE streamlined the call transfer and call handling processes to provide consistent call handling, reducing the time it takes to transfer a call, decreasing the length of calls, and reducing the amount of time a customer spends on hold

while speaking to a representative. For example, when comparing numbers between December 2011 through March 2012 and December 2012 through March 2013, there was an average reduction of 233 hours per month in the amount of time customers spent on hold during a call.

  - PGE introduced real-time monitoring that allows supervisors and leads to monitor customer service representatives' call times and offer assistance when needed to improve performance and increase our representatives' availability for customers. This directly impacts the customer's experience in contacting PGE, reduces customer wait times, and increases first call resolution with customers.
  - PGE created a centralized phone number and support team that customer service representatives can call to reach Contact Center supervisors, leads, and senior staff for help with policy and procedure questions, and direct call escalations to serve customers faster and more efficiently.

- Within the back office operations:
  - PGE simplified the review process for billing and credit reports to eliminate departmental duplications, verified and assessed the value of selected reports, and identified process improvement opportunities that led to the reduction of nearly 12,000 bill reviews per month.
- Within the Customer Strategies and Business Development (CS&BD) organization:
  - To get an advanced start on activities necessary to prepare for, select, and design the CIS and MDMS customer systems, PGE's work focused on a series of customer strategy and governance initiatives to establish high-level requirements for new customer information and meter data management systems and to improve alignment between strategy and operations. This work will support

PGE's efforts to design systems that will be long lasting and supportive of future customer requirements.

While some of these activities will continue into 2014, accomplishments in 2013 include:

- Completed analysis of PGE's residential market and developed new customer segments to help PGE better understand customers' behaviors and preferences. The new segments will facilitate more personalized interactions with customers by enabling PGE to begin to tailor communications and product and service offerings in ways that best meet customers' needs.
- Completed a comprehensive five-year strategy to deliver high-value interactions with customers through the channels (web, mobile, face-to-face, IVR) they prefer. Goals within the channel strategy include delivering simple, satisfying self-service transactions through digital channels, value-added interactions through face-to-face and phone channels and personalizing interactions to meet customers' preferences.
- Completed "as-is" customer experience maps documenting high-priority experiences such as billing, payment and outage, from the customer perspective. These maps lay the foundation for 2014 work to design best-practice customer experience treatments, which will drive our plans for the future.
- Created a new end-to-end product lifecycle and governance process to ensure PGE offers the appropriate blend of products and services that best meet our customers' needs. The new process places additional rigor and standardization around evaluating and prioritizing customer offerings based on market needs and operational impacts.

Q. What are the 2014 activities within the CET program?

A. 2014 CET activities fall primarily into two categories:

- Operational efficiency and effectiveness initiatives that will establish high-level requirements for the new systems and design business processes to take advantage of new systems. PGE will improve its current workforce planning and scheduling tool to optimize the allocation of employees to workloads across Customer Service Operations, and implement a tool for managing individual and team performance metrics. Additional activities will focus on creating organizational alignment within Customer Service operations to support employee adoption of change, and the extent to which skills, knowledge, and new behaviors are reinforced after new processes and systems are implemented improving benefit realization probability.

  PGE's 2014 work also includes the completion of a set of customer strategy and governance initiatives designed to map out the long-term strategy for how PGE can enhance its customer service offerings.

- 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. In addition, PGE will create a strategy for simplifying the current rate code and reports inventory to ensure a seamless transition to the new CIS.

Q. What are the 2015 activities planned for the CET program?

A. 2015 CET activities fall primarily into two categories:

- Continuation of operational efficiency and effectiveness initiatives. PGE will complete activities that focus on optimizing the allocation of employees to workloads across Customer Service Operations departments, and managing individual and team performance. In 2015, implementation of these new business processes and tools are planned to become fully operational and complete.
- Design and implementation of new systems. PGE plans to begin the implementation process for moving to the new CIS and MDMS systems. Other activities will focus on how business process design, associated with new technology, will operate within different parts of the Customer Service organization, as well as defining the technical architecture of the various internal systems that will interface with the new CIS and MDMS systems.

PGE expects that during 2015, the new customer systems build-out will begin. In addition to CIS and MDMS, PGE will implement a Knowledge Management system to better manage the processes and procedures that provide detailed work instructions for CSO functions with user-friendly features such as "search", "help", and "frequently asked questions". These tools will support employees, allowing them to better serve our customers.

Q. Please describe any changes to the CET timeline and roadmap of initiatives compared to UE 262.

A. PGE has made minor adjustments to the CET roadmap as provided in PGE Exhibit 1003. The CET roadmap specifies the sequence of the various initiatives beginning in 2012 and ending in 2018, and factors in the interdependencies of each of the initiatives to maximize operational efficiencies and effectiveness.

Q. Please provide an update on the overall expected costs and benefits for the CET program.

A. The CET program is a multi-year effort, and consequently, PGE's estimates for the later years (i.e., the years 2016-2018) are preliminary. PGE will be better able to estimate timing and costs after replacement software is selected. PGE expects that the full CET program, including the installation and configuration of the replacement systems and the operational improvement projects designed to optimize customer value, will cost approximately $22 million to $25 million of incurred O&M (representing no change from UE 262), and $72 million to $82 million of incurred capital[5] (estimated to be $70 million to $80 million of incurred capital in UE 262) 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 (see PGE Exhibit 1001).

The annual ongoing net O&M reduction is estimated to be $3 million to $5 million on an incurred basis once the program is complete in 2018, reduced from PGE's original estimate of approximately $4 million to $6 million[6,7] on an incurred basis. This decrease is due to a planning error that misclassified a group of employees overstating gains in efficiencies, resulting in an estimated average annual ongoing reduction in benefits of $1.1 million.

PGE will continue to refine expected timing, costs and benefits for the CET program as we improve estimates. In conclusion, PGE's work on the CET program is on scope, on budget, and we believe that we are on track to execute the activities outlined above in 2015.

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[5] Loaded and escalated range is estimated to be $33 million to $38 million O&M and $87 million to $99 million capital.
[6] The annual ongoing net O&M reduction on a loaded basis is estimated to be $6 million to $9 million.
[7] Net benefits include ongoing annual O&M reduction offset by increases in operating costs associated with new maintenance agreements, etc.

A. Fee-Free Bankcard

Q. Please summarize the UE 262 stipulation regarding fee-free bankcards.

A. In UE 262, PGE requested $1.6 million for a residential only fee-free bankcard offering with a targeted 15% adoption rate. In UE 262, PGE agreed to the stipulated amount of $0.5 million to develop and implement the program, without a stated adoption rate, but an agreement to launch the program by July 1, 2014 with the aim of meeting the stipulated amount. In addition, PGE agreed to make its best effort to report on the program's adoption rate, analyze the characteristics of participating customers, and report those results to the OPUC and other stipulating parties.

Q. What is the status of the 2014 program implementation?

A. PGE is on track to launch the bankcard program and eliminate transaction fees for credit or debit card payments made via the Web, IVR or at a PGE Community Office on July 1, 2014. PGE is working with its third party payment processors, with whom PGE has long-term contractual agreements, to deliver this functionality.

Q. Please describe PGE's fee-free bankcard program costs for 2015.

A. In 2015, PGE proposes to include in base rates the program costs of $1.8 million for credit and debit card payments. Changes to PGE's proposal for 2015 include the following:

- Expanding to include non-residential customers in alignment with the consumer experience in the retail marketplace;
- A targeted adoption rate of 11% by December 2015 that escalates from our current 3% fee-based bankcard usage by customers; and
- Transaction fees associated with necessary financial and third party vendor processing costs.

Q. Please describe your adoption methodology for fee-free bankcards.

A. Adoption rate calculations are illustrated in PGE Exhibit 1004. Because PGE has not yet developed experience with the actual adoption of a fee-free bankcard program by our customers, we base our estimate on a set of assumptions and considerations. We assume we will have a similar adoption rate as a neighboring utility that has implemented a fee-free bankcard program for its residential customers. We anticipate that PGE's program will continue to grow in 2015 and beyond in part due to customers shifting from other payment methods as they learn about the program. As bankcard payment continues to grow as a consumer preference in the retail marketplace, PGE will need to be able to meet rising customer expectations. PGE anticipates that as program adoption increases over time, so will the cost associated with the service of processing bankcard remittance.

Q. Did PGE conduct additional research regarding credit card adoption rates?

A. Yes. We surveyed a total of five utilities that currently offer fee-free bankcard programs to obtain information about their programs. While PGE concluded that the experience of a neighboring utility would be the closest indicator of potential adoption rates for the PGE program, we also sought information from other sources to gain insight on their adoption rates and program implementation. PGE Exhibit 1005 provides the following data on three[8] of the programs we reviewed: current and historical adoption rates; fee-free program start dates; the types of cards accepted; channels available for use; transaction types (i.e., one-time or recurring payments); and marketing/promotional efforts related to each program. This research shows that current adoption rates range from 9% to 35%.

[8] Two of the utilities declined to authorize PGE to publish their data in this filing.

V. Conclusion

Q. You stated that PGE's goal for Customer Service is to deliver value to its customers by providing excellent service at a reasonable price. Are the initiatives planned within your Customer Service organizations necessary to achieve this?

A. Yes. 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 to operate our business in a smart, efficient and cost effective way, while delivering the products and services that meet customer expectations and enhance their experience.

VI. 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 twenty 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-six 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**
1001C	Customer Engagement Transformation Cost Estimates 2015-2019
1002C	2013 Survey Results for MSI and JD Powers
1003	Customer Engagement Transformation (CET) Roadmap
1004C	Bankcard – Adoption Rate Calculation
1005	Bankcard Outreach to Utilities

EXHIBIT 1001C

Confidential

EXHIBIT 1002C

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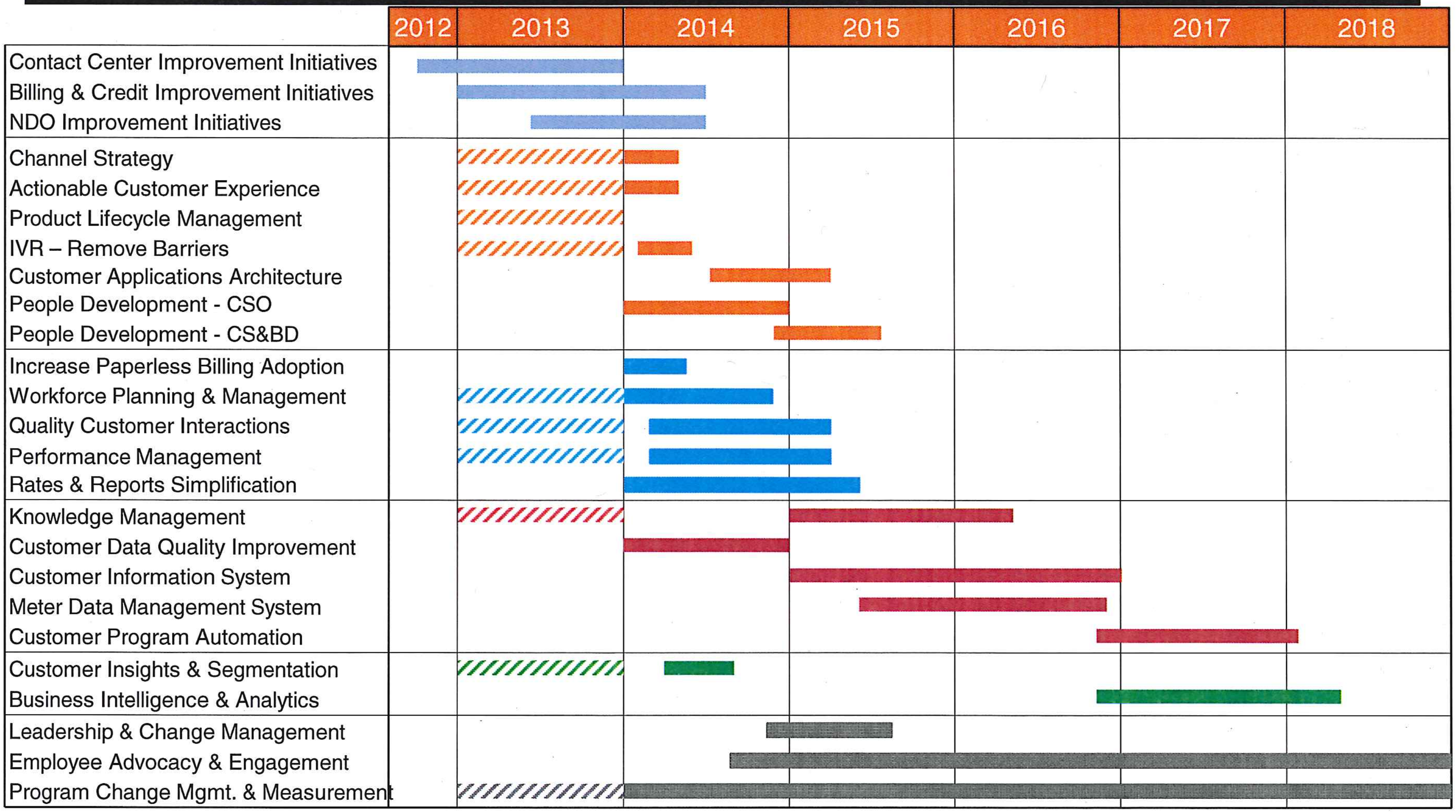
Customer Engagement Transformation
Roadmap October 2013



CATEGORIES: Improvement Initiatives; Strategy & Governance; Operational Efficiencies; Analytics & Reporting; Systems; Change Management; Shaded bars indicate work started early, using existing budgets

1/31/2014

*This Roadmap is a living document and subject to change.

Customer Engagement Transformation

Category Descriptions

Improvement Initiatives: Implement numerous process improvements to increase overall effectiveness and efficiency in the operational areas of Contact Center, Billing, Credit, and Network Data Operations.

Strategy & Governance Initiatives: Provides the long-term strategy for gaining better insight into customer behaviors - such as channel preference (web, phone, community office, etc.) – to deliver products and services faster and more cost effectively. Also develops the high-level system requirements and selects the software packages that best meet PGE's customer and regulatory requirements.

Operational Efficiencies: Enhance current workforce planning and scheduling tool to optimize the allocation of employees to workloads across Customer Service, increasing employee productivity and enabling cost efficiency. Finally, PGE will design and implement a tool for managing individual and team performance metrics.

System Replacements: Preparation for system replacements by completing technical activities such as reviewing customer data for accuracy and consistency; involves the purchase of a data quality tool. This effort includes implementation of: a new Customer Information System (CIS) and Meter Data Management System (MDMS); a new Knowledge Management System that supports employees with convenient features such as "search", "help", and "frequently asked questions"; and a Customer Program Automation system that will utilize improved customer data through automation to deliver accurate measurement of program adoption and effective, efficient product management.

Analytics & Reporting: Update and enhance customer data in order to drive a more tailored, targeted marketing of products and services to customers.

Change Management: Provides overarching programmatic support to improve the rate of employee adoption and proficiency in using new processes and systems in order to realize benefits earlier and reduce project risk.

EXHIBIT 1004C

Confidential

UTILITIES OFFERING FEE FREE BANK CARD PROGRAMS

Utility	No Fee Program Launch	Current Adoption Rate	Card Types Accepted (Y/N) Debit	Credit	Visa	Mastercard	Channels Avail. For Card Payments	Transaction Types One Time	Recurring	Historical Adoption Rates	Marketing / Promotions
Northwest Natural Gas	2012	9%	Y	Y	Y	Y	Web, IVR	Y	Y (2014)	Nov 2012 - started at 2% and ended at 4%; Dec. 2012 ended at 5%; Jan 2013, ended at 7% and maintained through Oct.; Nov 2013 ended at 8%; and Dec 2013 reporting close to 9%.	N/A
Flint Energies	around 1980	35%	Y	Y	Y	Y	Web, IVR, Kiosk, CSR [1]	Y	Y	Didn't have historical adoption rates.	N/A
Snohomish PUD	Oct. 2008	19.3%	Y	Y	Y	Y	Web, IVR	Y	Y	Q4 2008: 1.2% [2] 2009: 7.3% 2010: 10.2% 2011: 13.3% 2012: 16.4% 2013: 19.3%	The fee-free bank card program was promoted the same as any other offering.

Footnotes:

[1] Flint: Learned that due to high volume of Kiosk usage, they needed side-by-side kiosks

[2] Snohomish Payment Adoption Rates

	Fee-Free Visa/MasterCard (credit/debit/PD)	Other Fee-Free Pinless Debit	Automated Clearing House (ACH)
Q4 2008	1.20%	0.00%	0.60%
2009	7.30%	0.00%	4.10%
2010	10.20%	0.30%	6.40%
2011	13.30%	0.40%	7.80%
2012	16.40%	0.60%	9.50%
2013	19.30%	0.60%	10.70%

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 283

Cost of Capital

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Patrick G. Hager
William J. Valach
Brett Greene

February 13, 2014

Table of Contents

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 qualifications are included at the end of PGE Exhibit 500.

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. My qualifications are included at the end of this testimony.

My name is Brett Greene. I am the Assistant Treasurer and Director of Treasury & Tax for PGE. I am responsible for managing the company's treasury function including financing as well as the tax department. My qualifications are also 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 2015 test year. PGE's requested cost of capital and capital structure is necessary to maintain its current credit profile for access to the debt and equity markets, to fund its significant capital investments planned for 2015 and later years, 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 authorized cost of capital is provided by the Bluefield[1] and Hope[2] United States Supreme Court decisions as well as ORS 756.040.

[1] Bluefield Water Works v. Public Service Comm'n - 262 U.S. 679 (1923)

Q. What are PGE's financial goals?

A. PGE's overall financial goals include the following:

- Maintaining investment grade credit ratings;
- Accessing financial markets at reasonable terms to provide liquidity for operations and capital expenditures;
- 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;
- Setting retail prices at a level sufficient to recover prudently incurred costs, including an overall return on utility investment, while taking into account the economic conditions facing our customers; and
- Maintaining a capital structure of approximately 50% debt and 50% equity over time.

Q. What is PGE's requested overall cost of capital for this filing?

A. We request and support a 7.779% cost of capital for the 2015 test year. This cost of capital includes a 10.00% authorized Return on Equity (ROE) based on the recommended range provided by of Dr. Zepp in PGE Exhibit 1200. This point estimate is for revenue requirement purposes and is based on our recommended range of 7.779% to 8.401% for PGE's cost of capital and a recommended range of 9.9% to 10.6% for PGE's authorized 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 2015 capital structure.

[2] FPC v. Hope Nat. Gas Co. - 320 U.S. 591 (1944)

Q. Dr. Zepp's recommended range for PGE's authorized ROE is 9.9% to 10.6%. How did you determine your point estimate of 10.0%?

A. Dr. Zepp's range is based on a sample of similar electric utilities but their characteristics are somewhat different than PGE. In addition, several different methods are used to derive an appropriate required return on equity. Dr. Zepp notes that the mid-point of the range is 10.3% but recommends 10.5% as point estimate for PGE's ROE. We lowered our request to 10.0% based on two factors:

1) PGE is requesting several accounting orders as part of this filing that may help mitigate PGE's risks. Accounting orders that allow PGE to amortize environmental costs over several years assures investors that PGE will generate revenue to pay for the costs. Also, an order that allows PGE to 'carve out' wind power costs, including productions tax credits (PTC), will help stabilize PGE's earnings. PGE Exhibit 500, Section VI and work papers to PGE Exhibit 1100 discuss this proposal.

2) We recognize that Oregon, including our service territory, still hasn't fully recovered from the Great Recession and using the lower end of the recommended range helps mitigate the impact of increased costs while providing a fair investment opportunity to our shareholders.

Q. How did you derive the overall recommended cost of capital?

A. We first forecasted the cost of the debt and equity components by considering 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 2015

Component	Average Outstanding ($000) [1]	Percent of Capital [2]	Component Cost	Weighted Cost
Long-term Debt	$2,343,818	50.00%	5.557%	2.779%
Common Equity	$2,275,659	50.00%	10.00%	5.000%
Total	**$4,619,477**	**100.00%**		**7.779%**

[1] "Average Outstanding" reflects PGE's projected average values of long-term debt and common equity for 2015.

[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 report on PGE's funding strategy for the capital projects. Section III discusses the effects of regulation, including PGE's power cost adjustment mechanism (PCAM). In Section IV, 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 V. In Section VI, we discuss PGE's capital structure. Section VII provides Mr. Valach's and Mr. Greene's qualifications.

II. Recent Financing Activities

Q. Are there overriding principles that PGE follows in determining when it seeks market financing?

A. Yes. In general, our overriding principle is to obtain financing at the lowest cost, subject to various risk factors. In addition, we seek to efficiently utilize cash to ensure that PGE has cash in time to fund its business, but does not have significant amounts of cash on hand that is not required shortly. For protection against any unforeseen changes in cash flow, we rely on our revolving lines of credit to ensure liquidity.

Q. How does PGE determine the timing of its financing?

A. PGE forecasts its cash needs, which include capital expenditures, debt maturities, dividends and changes in working capital, and attempts to match its long-term financings in order to meet those requirements. Closely matching financing needs with the required payments while continually monitoring capital market risk (i.e. interest rate and stock price) helps achieve lower financing costs. As we discuss below, PGE has frequently used a "call forward" for its long-term bonds and recently executed an equity forward contract and has found these financing structures to be a viable method to reduce market volatility.

A. Long-Term Bond Financings

Q. Did PGE issue long-term debt in 2013?

A. Yes. PGE successfully issued $380 million of new long-term debt in 2013. The entire amount was issued as fixed rate first mortgage bonds with an average maturity of approximately 31 years. The bonds were all issued in the private placement market in four separate tranches designed to time PGE's cash needs with corresponding capital expenditure requirements and mitigate interest rate volatility.

Q. Did PGE secure debt financing at attractive rates?

A. Yes. The coupon rates ranged from 4.47% to 4.84% and averaged 4.59%, representing some of the lowest cost long-term financing in PGE's history.

Q. During 2013, there was talk that the Federal Reserve (Fed) might begin to pull back on their quantitative easing measures. Did PGE use any hedging tools to mitigate a rising treasury rates environment?

A. Yes. PGE used a delayed draw feature that is available only in the private placement market to lock in the coupon rate in advance of issuing the bonds (and taking the cash) for 3 of the 4 tranches.

Q. Did this hedging feature come at an additional cost?

A. No. PGE used the delay for only 2-3 months per tranche and the market currently does not charge for a delay of that length. Delays under this feature extending beyond 3 months typically cost approximately 3-5 Basis Points (bps)[3] per month.

Q. Did customers benefit from this hedging?

A. Yes. Hedging is designed to reduce or mitigate certain types of risk associated with the transaction. In this case, PGE was concerned with interest rate volatility and possible market disruption or funding risk, specifically a rise in long-term interest rates or a period when access to the financial markets is not available. While it was possible that interest rates could have declined further in 2013, we were primarily concerned with the significant volatility during the year and the consensus forecast of increasing interest rates. Thus, we believed it prudent to remove interest rate volatility risk and ensure funding through the delayed draw hedging technique. In this case, PGE estimates that customers will save in

[3] Basis Points (Bps) – a unit that is equal to 1/100th of 1%, and is used to denote the change in financial instrument.

excess of $15 million in interest during the life of the bonds as a result of PGE's use of the delayed draw combined with long term rates increasing 50-100 basis points in 2013.

Q. What is the effect of this funding on PGE's risk profile?

A. We believe the funding will have a long-term positive effect on PGE's risk profile. PGE issued fixed-rate, longer term debt with a duration that closely matches the average life of our new assets. Doing so reduces near term refinancing risk and also locks in these low interest rates for the long term. We note that we were effective in our financing because long term rates rose in excess of 50-100 basis points in 2013, and are generally forecast to continue to rise.

B. Equity Financing

Q. PGE issued 2.4 million shares of common equity in 2013. How did PGE raise this equity?

A. As mentioned earlier, PGE used a forward structure that is commonly used by utilities that allows the company to lock in a common share issuance price but actually issue the shares and receive cash when PGE requires the cash and to maintain a balanced capital structure. This forward structure allowed PGE to lock in equity pricing at a very favorable level of $29.50 per share. PGE has drawn a portion of the cash and issued 1,665,000 of the shares at closing and an additional 700,000 shares in August of 2013. We expect to issue the remaining 10.4 million shares in 2014 as our capital expenditures progress for our new generating plants. This method of equity issuance also allows PGE to better manage our desired long-term 50/50 capital structure by eliminating a one-time swing in equity had the company executed a common equity one-time offering.

Q. How did customers benefit from the forward structure?

A. Because PGE can draw on the forward structure as it needs cash, we minimize the amount of 'idle' cash and better balance our capital structure over time. PGE's financing costs should be lower, all else equal, because our capital structure will be less volatile.

III. Regulation and Cost of Capital

Q. PGE has always tried to maintain good credit ratings and quality. Are these important?

A. Yes. Investment grade ratings and good credit quality are essential for PGE to secure financing at reasonable rates and to maintain its access to wholesale energy markets, especially in today's volatile financial environment. When interest rates are volatile, lenders prefer to lend to firms with better credit quality. Without an investment grade rating, PGE's access to financing would be more limited and at higher rates.

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 the necessary cash and liquidity for its operations and capital investments needed to offer safe, reliable, and reasonably-priced electricity service.

In addition to the capital requirements of our base business and the construction of new generation assets, 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 are PGE's current bond ratings?

A. PGE's current bond ratings for secured long-term debt are A1 from Moody's and A- from Standard & Poor's (S&P). PGE's credit ratings are provided in PGE Exhibit 1102.

Q. Does the Commission's regulatory policy have an impact on PGE's credit quality?

A. Yes. Regulatory policy that supports recovery of prudent costs is essential to maintaining a stable, investment grade credit rating. Both Moody's and S&P consider regulatory policy a key factor in their determination of a utility's creditworthiness. Moody's places equal weights to four subfactors (Regulatory Framework, Ability to Recover Costs and Earn Returns, Diversification and Financial Strength) to derive two rating factors: "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 environment 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.

Q. Have financial analysts or rating agencies noted any concerns regarding regulatory outcomes as they pertain to PGE?

A. Yes. Sell side analysts have noted that the Public Utility Commission of Oregon (OPUC) has historically allowed ROEs that are slightly below the national average but they also note that recent settlements have included constructive outcomes such as forward looking test years, partial decoupling, and a renewable investment tracking mechanism.[6] S&P highlighted a concern that PGE's "somewhat weak power cost adjustment mechanism"[7]

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[4] "Rating Methodology – Regulated Electric and Gas Utilities." Moody's Investor Service- December 23, 2013.
[5] "Key Credit Factors for the Regulated Utilities Industry." Standard & Poor's- November 19, 2013.
[6] "Improving valuation reflects outlook – reinstate at Neutral." Bank of America/Merrill Lynch- 20 December 2013
[7] RatingsDirect. Summary: Portland General Electric Co. Standard & Poor's June 4, 2013

contained provisions that weakened its structure, notably the deadbands and an earning test requirement.

Q. Didn't Moody's just upgrade PGE based on their more favorable view of the credit supportiveness of the US regulatory framework?

A. Yes. On January 30, 2014 Moody's announced several utility upgrades as part of their redesign of the framework and overall risk analysis of the utility sector. They believe that regulatory jurisdictions have become more credit supportive and Moody's upgrades reflect this.[8] In particular, Moody's decision acknowledges the "high degree of support" offered by the OPUC, which they view as "above average."

Q. Are S&P's and Moody's view of Oregon's regulatory environment in conflict?

A. No. S&P in its June 2013 report notes that Oregon is a credit-supportive jurisdiction, as does Moody's. S&P continues to identify the PCAM as inferior to other states power cost mechanisms.

Q. Have other financial analysts expressed concerns regarding the PCAM?

A. Yes. Most electric utilities tend to have a 'pass through' of their power costs if a PCAM is in place, with no deadbands. So, PGE's asymmetrical deadband is unique. Thus, it is not unexpected that analysts' concerns should 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."[9] Wellington Shields & Co. LLC noticed that "the major

[8] Moody's Investor Service. US utility sector upgrades driven by stable and transparent regulatory frameworks. February 3, 2014
[9] Deutsche Bank Markets Research. Better value for uncertain times; adding selectively to Buy list. October 1, 2013

POR negative has been earnings volatility created by an adverse fuel clause."[10] Wells Fargo comments: "POR's power cost adjustment mechanism (PCAM) does not provide for full pass through of fuel and purchased power costs, which introduces EPS and cash flow volatility when actual net variable power cost (NVPC) are different from the annual forecast. When costs are higher than expected, the first $30 MM, or approximately $0.25 per share after-tax, is absorbed by shareholders before 90/10 sharing between customers/ shareholders kicks in."[11]

Q. How does increased earnings volatility impact PGE's cost of capital?

A. Financial theory tells us that, all else equal, increased earnings volatility results in increased uncertainty or risk. Investors and creditors require greater compensation for owning an investment with more risk. 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 common stock increasing the cost to finance the PGE activities.

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[10] Wellington Shields & Co.LLC Rate Base Growth Stock-a Best Buy for 2014. January 9, 2014
[11] Wells Fargo Securities. Equity Research. Portland General Electric Company. September 26, 2013

IV. Financial Markets and Economic Overview

Q. Please provide an overview of the market conditions during 2011 - 2013.

A. The world economies continue to attempt to recover from a very steep economic decline, which for some began almost seven years ago 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 "Great 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, continue to have significant issues with their borrowing liquidity and at times seem to approach default;
- The housing market in the US has showed signs of growth in 2013 but there is considerable uncertainty regarding the composition of the housing inventory and when this inventory will come on the market; and
- Although the equity markets in the US have exceeded their levels before the Great Recession, there remains considerable uncertainty as to its strength.

The US federal budget deficit continues to remain at exceptionally high levels and, although Congress has crafted a short-term solution to the budget process, Congress does not seem any closer to a deficit 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 and not much better in 2013. 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. Finally, we have seen interest rates rise in 2013 and they are expected to continue to rise.

Q. Do other potential risks remain in the U.S. or global economies?

A. Yes. 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 and Volker rule).

Q. How will banks meet these new requirements?

A. First, the banks began tightening of lending standards during 2012, making it more difficult for firms to access credit, potentially increasing firms' costs to obtain credit 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 Fed[12], leaving less available for lending.

Dodd Frank is forcing banks and marketers to decide if the added cost of compliance and reporting is worth the margins of remaining a liquidity provider. In 2015, we could see some financial stress passed through to PGE and other utilities as banks comply with the Basel III regulation (full compliance is required by 2019). The impact of this would be an increase in the costs of carrying our credit facilities, as well as upward pressure on the ability to execute FMB and equity issuances at the prices (spreads) that we have seen during the last couple years.

Q. Will these new requirements affect PGE's ability to access funds?

A. Yes. These new requirements have tightened the availability of those funds, which would drive costs higher.

B. Liquidity Management

Q. What is PGE's strategy for liquidity management and related revolving credit facility sizing?

A. PGE's strategy is fourfold:

[12] http://libertystreeteconomics.newyorkfed.org/2012/12/why-or-why-not-keep-paying-interest-on-excess-reserves.html.

- Maintain financial flexibility by carrying sufficient credit levels to support both operational and power supply needs over a five year forward looking time horizon.
- Support a designation of strong or better from rating agencies (based on Moody's and S&P's interpretation of our revolving credit facility and cash needs).
- Fund short-term debt requirements as efficiently as possible utilizing commercial paper or revolving credit facility loans as appropriate. Issue letters of credit in lieu of cash collateral if pricing dictates with the added benefit of credit risk mitigation.
- Manage market exposure related to maturing lines of credit by maintaining multiple facilities with varying maturity dates.

Q. Has PGE separately analyzed its revolver requirements?

A. Yes. PGE has again 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 in 2014 if there is an unexpected change in cash flow. Our results for PGE liquidity needs for general operations were between a low of $345 million and a high of $475 million while our power supply liquidity needs were between a low of $80 million and a high of $525 million.

Q. How did you perform your analysis?

A. If PGE is a net buyer then a decrease in market prices increases collateral requirements. For power supply liquidity needs, we began with PGE's actual November 2013 collateral position and then decreased wholesale power prices by 20%, 30%, and 50%, assuming no changes in our current strategy for power procurement. For the extreme case (50% price reduction), we also assumed a downgrade in PGE debt rating to below investment grade. As shown in Table 3 below, the liquidity required for power supply ranges from $70-$90 million, at 20% decrease in prices, to $520-$530 million, at 50% decrease in prices.

Table 3
Power Supply Liquidity Analysis
($ millions)

	Collateral Range	Revolver Need
20% Price Change	$70-$90	$80
30% Price Change	$180-$200	$190
50% Price Change	$520-$530	$525

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 and wind conditions, and forced plant outages. We developed several scenarios to "stress" the liquidity requirements of general operations. Under the four scenarios, PGE would require approximately $345-$475 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 Earnings Before Interest, Taxes, Depreciation and Amortization (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 a 15% 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 and 2015. For Standard & Poor's, we would also be rated "adequate" with minimal upside potential based on their rating criteria. Based on this set of analyses, we determined that our current revolver capacity of $700 million is adequate for the test year.

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 2015?

A. PGE has forecast 2015 broker fees using 2014 forecast of \$0.515 million as a basis and escalating at approximately 1.72%, the estimated CPI provided by Global Insight, for expected increases in fee rates. Broker fees for the 2015 test year are estimated to be about \$0.524 million.

V. Cost of Long-Term Debt

Q. How did you calculate the cost of long-term debt for 2015?

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, 2013, as well as bond issuances and retirements expected in 2014 and 2015. 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 2015 test year has decreased from that estimated for 2014 by almost 17 basis points. Table 4 below summarizes PGE's cost of long-term debt for 2015.

Table 4
PGE's Cost of Long-Term Debt ($000)

	2015 Forecast	2014 Forecast	Difference
Principal Amount	$ 2,344,400	$ 2,091,400	$ 253,000
Annual Interest Cost	$ 130,278	$ 119,754	$ 10,524
Effective Interest Rate	**5.557%**	**5.726%**	**-0.169%**

Q. What future debt issuances did you include in your analysis?

A. We expect to issue $350-400 million in long-term fixed rate debt during 2014, but have included $365 million in our calculation as our current best estimate. We also expect to issue an additional $200 million of long-term debt in 2015.

Q. What is the expected term, coupon rate, and issuance cost for the bonds to be issued in 2014 and 2015?

A. PGE currently expects to issue four tranches of First Mortgage Bonds (FMBs) in 2014 that will each carry a coupon rate of 4.95% for a term of 30 years and one issue that will carry a coupon rate of 4% for a term of 10 years. The $150 million FMB scheduled for 2015 is expected to carry a coupon of 5.25% for a term of 30 years. The $50 million is expected to carry a coupon of 4.3% in 2015 for a term of 10 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 subset of the Company's investment banks and a forecast of treasury rates from Global Insight.

Q. Is any long-term debt maturing in 2014 or 2015?

A. Yes. $70 million of 3.46% 5-year FMBs are maturing on January 15, 2015. These debt issuances and redemptions are detailed in PGE Exhibit 1101.

Q. Since UE 262 settlement discussions, what impacts have PGE's overall financing activities had on customers?

A. Because we are able to take advantage of the lower interest rates, our financing activities have reduced costs to customers.

VI. Capital Structure

Q. How did you determine the appropriate capital structure for 2015?

A. We evaluated PGE's capital structure using the forecasted income statement and balance sheet for 2015, as well as our expected financings through 2015. 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 262 (Order No. 13-459), 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 common equity in 2015?

A. No. At this time PGE does not anticipate additional equity issuances but we will provide an update if our financing plans change**.**

Q. Are you seeking a different capital structure than that in UE 262?

A. Not at this time. In UE 262, Order No. 13-459 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 equity to exceed 50% by the end of the test year and during 2016 to accommodate the continued construction progress.

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 Accounting Standards Codification 810 (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. 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: S&P "imputes" additional debt to PGE's capital structure based on the quasi fixed payments from long-term PPAs. S&P believes that because of these quasi-debt instruments an adjustment must be made to the capital structure to reflect the additional leverage of PPA contracts. Significant increases in the debt ratio are a quantitative trigger for potential ratings downgrades. A ratings downgrade by S&P from PGE's current 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[13] as of December 31, 2012 based on our current contracts.

[13] PGE 2012 SEC Form 10K report, page 57.

- 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 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 the timing of it; 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. We note that with wind, the weather risk is even more pronounced. There is the cost of replacing the lost generation from the market, but there are also two additional effects. First, although total wind generation may equal that expected for the year, the <u>timing</u> of the wind may be quite different, e.g., wind may appear in the shoulder hours or months instead of peak. Second, wind generation also provides PTCs, which affects income taxes. Thus, earnings are more volatile with wind fluctuations. Again, having the Renewable Portfolio Standard (RPS) carve out will provide PGE with less volatile earnings.

- 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 has not completely recovered since then. The preliminary estimate for the state of Oregon unemployment rate in December 2013 was 7.0%, 0.3% higher than the US unemployment rate.

- 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. While PGE has been acquiring renewables at low cost and will continue to look for low cost opportunities, we face 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 financial contingencies: as noted in our SEC annual 10-K and quarterly 10-Q filings[14], PGE has several financial contingencies including a possible adverse Trojan decision. Some of these contingencies are less likely, but there is uncertainty in the financial markets regarding these financial contingencies, which is viewed as a weakness by the financial community.
- Uncertain federal and state 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 various equity analysts include at least one of the risks listed above. For example, Wells Fargo mentions hydro conditions as a risk factor in

[14] http://investors.portlandgeneral.com/secfiling.cfm?filingID=784977-13-12
Starting with page 115- 2012 SEC Form 10-K
http://files.shareholder.com/downloads/POR/2524192942x0xS784977-13-74/784977/filing.pdf
Starting with page 30- the most recent 11/1/13 SEC Form 10-Q

September 26, 2013 research release. And J.P. Morgan writes: "The fuel and purchased power recovery clause authorized for POR exposes the company to earn near term fluctuations in hydro 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 POR's near-term earnings."[15]

Q. Can PGE mitigate 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 mitigate them, PGE remains significantly exposed.

Q. What is PGE doing to mitigate the risks outlined above?

A. PGE is proactively implementing programs that will better prepare us for adverse events. For example, recovery from catastrophic events remain a key strategic focus of PGE The office of Business Continuity and Emergency Management has developed formal recovery plans to address disasters and implement emergency management procedures. Another risk category is PGE fuel supply. PGE is developing backup plans for fueling in the event of extended outages of natural gas pipelines or coal supply. We are looking at gas dispatch modeling and storage solutions and performing cost-benefit analysis of re-establishing ability of gas plants to run on oil if pipeline interruptions occur. Finally, we have included in our filing requests for mechanisms, such as the RPS 'carve out' and the environmental costs accounting order, that will mitigate some of the financial contingencies.

Q. Could the risks addressed above alter the cost of capital you request?

[15] J.P. Morgan. North American Equity Research. Portland General Electric Co. 04 November 2013

A. Yes. If these risks result in financial distress to the Company and/or its peers, the cost of long-term debt and the cost of equity will increase, with a resulting long-term cost impact on customers.

VII. Qualifications

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. Mr. Greene, please state your educational background and experience.

A. I received a Bachelor of Science degree in Business Administration from the University of Portland in 2000. I received a Master in Taxation from Golden Gate University in 2009. I joined PGE in 2010 as Tax Manager and was Manager of Corporate Finance and Assistant Treasurer from August 2012 to December 2012. Since January 2013, I have held the title of Assistant Treasurer and Director of Treasury & Tax.

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, 2015 - 2015 Test Year

Updated 01.16.2014

(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)	Net to 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	0.853%	0.080%
2	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	2.133%	0.149%
3	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	2.133%	0.150%
4	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	7.465%	0.496%
5	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	4.265%	0.284%
6	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	7.251%	0.425%
7	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	5.545%	0.327%
8	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	3.199%	0.189%
9	7000000693	FMB	6.800% Series	15-Jan-09	15-Jan-16	7	6.800%	$67,000,000	$0	$0		$67,000,000	6.919%	0.000%	$0	$0	0.000%	0.000%
10	7000000181	FMB	6.100% Series	13-Apr-09	15-Apr-19	10	6.100%	$300,000,000	$2,608,223	$0	5	$297,391,777	6.218%	99.131%	$300,000,000	$297,391,777	12.796%	0.796%
11	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	6.398%	0.350%
12	7000010695	FMB	3.460% Series	15-Jan-10	15-Jan-15	5	3.460%	$70,000,000	$0	$0	6	$70,000,000	3.609%	0.000%	$0	$0	0.000%	0.000%
13	7000000185	PCB	Clstrp 98A Fixed	11-Mar-10	1-May-33	23	5.000%	$97,800,000	$688,885	$1,521,911	7	$95,589,204	5.168%	97.739%	$97,800,000	$95,589,204	4.172%	0.216%
14	7000000036	PCB	Brdmn 98A Fixed	11-Mar-10	1-May-33	23	5.000%	$23,600,000	$166,234	$912,065	7	$22,521,701	5.346%	95.431%	$23,600,000	$22,521,701	1.007%	0.054%
15	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	2.474%	0.097%
16	2013-1	FMB	4.47% Series	27-Jun-13	15-Jun-44	31	4.470%	$150,000,000	$1,121,463	$0		$148,878,537	4.515%	99.252%	$150,000,000	$148,878,537	6.398%	0.289%
17	2013-2	FMB	4.47% Series	29-Aug-13	14-Aug-43	30	4.470%	$75,000,000	$560,731	$0		$74,439,269	4.516%	99.252%	$75,000,000	$74,439,269	3.199%	0.144%
18	2013-3	FMB	4.74% Series	15-Nov-13	15-Nov-42	29	4.740%	$105,000,000	$671,615	$0		$104,328,385	4.781%	99.360%	$105,000,000	$104,328,385	4.479%	0.214%
19	2013-4	FMB	4.84% Series	16-Dec-13	15-Dec-48	35	4.840%	$50,000,000	$319,817	$0		$49,680,183	4.878%	99.360%	$50,000,000	$49,680,183	2.133%	0.104%
20	2014-1	FMB	2044 Forecast	31-Jul-14	31-Jul-44	30	4.950%	$95,000,000	$926,250	$0	9	$94,073,750	5.013%	99.025%	$95,000,000	$94,073,750	4.052%	0.203%
21	2014-2	FMB	2024 Forecast	31-Aug-14	31-Aug-44	30	4.950%	$60,000,000	$450,000	$0	9	$59,550,000	4.999%	99.250%	$60,000,000	$59,550,000	2.559%	0.128%
22	2014-3	FMB	2044 Forecast	30-Sep-14	30-Sep-24	10	4.000%	$75,000,000	$731,250	$0	9	$74,268,750	4.120%	99.025%	$75,000,000	$74,268,750	3.199%	0.132%
23	2014-4	FMB	2044 Forecast	31-Oct-14	31-Oct-44	30	4.950%	$50,000,000	$487,500	$0	9	$49,512,500	5.013%	99.025%	$50,000,000	$49,512,500	2.133%	0.107%
24	2014-5	FMB	2044 Forecast	30-Nov-14	30-Nov-44	30	4.950%	$85,000,000	$828,750	$0	9	$84,171,250	5.013%	99.025%	$85,000,000	$84,171,250	3.626%	0.182%
25	2015-1	FMB	2045 Forecast	15-Jan-15	15-Jan-45	30	5.250%	$150,000,000	$1,462,500	$0		$148,537,500	5.315%	99.025%	$150,000,000	$148,537,500	6.398%	0.340%
26	2015-3	FMB	2025 Forecast	15-Mar-15	15-Mar-25	10	4.300%	$50,000,000	$375,000	$0		$49,625,000	4.393%	99.250%	$50,000,000	$49,625,000	2.133%	0.094%
								$365,000,000	4.428%									
			Annual expense from loss on reacquired debt					4.75%	4.15%	$167,007		($167,007)						
			Totals					$2,846,400,000	$19,709,803	$16,878,024		$2,444,812,173			$2,344,400,000	$2,307,979,180	100.00%	5.550%
			Cost of LT Debt (includes annual expense from loss on reacquired debt)															5.557%

Losses on Other Reacquired Debt	Issue Date	Mat. Date	Reacquisition Date	Gross Proceeds	Total Gain/Loss to Amortize	2014 Expense	
7000000 5.450% Colstrip 98B Fixed PCB due (	1-May-03	1-May-33	1-May-09	$21,000,000	$411,622	$17,139	
7000000 Trojan 90A Fixed	1-Jul-98	1-Aug-14	15-Jan-11	$9,600,000	$63,836	$10,459	1
7000000(6.500% Series	15-Jan-09	15-Jan-14	29-Dec-11	$63,000,000	$7,448,429	$139,409	9
						$167,007	

Footnotes

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 "DD&E Issue Costs" (column J) was updated to reflect $222,000 discount to par at issuance.

6 "DD&E Issue Costs" (column J) was updated to reflect actual issuance expenses.

7 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 Per 'Rate Base Roll-forward DRAFT_1.xlsx' - 5312013; assumes 80bps for 10-year and 100 bps (as % of principal) for 30-year

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	A1	1/30/2014
Senior Unsecured	BBB	2/21/2012	A3	1/30/2014
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
"Rating Action: Portland General Electric Company" January 30, 2014 Moody's Global Credit Research

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 283

Return on Equity

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Thomas M. Zepp

February 13, 2014

Table of Contents

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 principal of Zepp Consulting LLC. I am also a vice president of Utility Resources, Inc. My business address is 2845 Holiday Drive, South, Salem Oregon.

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"). I also call the RROE the "cost of equity" in this testimony. My study is based on data available to investors in December 2013.

Q. What are the results of your analysis?

A. The results of my analysis are provided in the table below:

Basis for Estimate	Estimated Cost of Equity for a Benchmark Sample of Electric Utilities
First Discounted Cash Flow ("DCF") Analysis	9.6%
Second DCF Analysis	9.6%
Third DCF Analysis	9.9%
First Risk Premium ("RP") Analysis	10.2% to 11.4%
Second RP Analysis	10.8% to 11.2%
Third RP Analysis	10.4%
Range of Earned, Forecasted and Authorized ROEs	10.2% to 10.6%
Estimated Range of Benchmark Costs of Equity	9.9% to 10.6%
Mid-point of equity cost range for sample	10.3%
Indicated Required ROE for PGE	10.5%

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 10.3%. PGE's requested ROE of 10.0% falls within my estimated cost of equity range of 9.9% to 10.6% for benchmark sample but is very conservative given the evidence that the Company is more risky than the average utility in that sample.

Q. Please discuss current economic activity and other factors that put your cost of equity estimates in perspective.

A. While there are some indications the U. S. economy is recovering from the most severe recession in memory, the recovery continues to be slow and investor concerns about the risks of equity investments continue for a number of reasons. In November 2013, the national jobless rate was 7.0% and there was mediocre growth in GDP. Bickering between members of Congress continues and investors have good reasons to be concerned that actions taken by our Washington politicians may be detrimental to the speed of the economic recovery. Also, there is risk that potential compromises on increases in the national debt ceiling will not be favorable for equity investors.

Interest rates for long-term Treasury securities have dropped even though S&P has down-graded Treasury securities of the United States from AAA to AA+. Even with this down-grading, investors are still pricing Treasury securities at relatively high levels and thus accepting lower yields than are available on "lower risk" AAA corporate bonds. To a large extent, the low Treasury rates are the result of actions of the Federal Reserve which has been buying longer term bonds to support the lower interest rates. As the economy recovers, we should expect "tapering" of that Federal Reserve program which will lead to fewer bonds being purchased and higher interest rates.

Also, current interest rates are now very low when compared to 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, and dropped to 2.92% in 2012. As the economy recovers, we should expect the Federal Reserve's quantitative easing will be reduced and interest rates will increase. As of November 26th, long-term Treasury rates averaged over 3.8% and analysts expect all interest rates to bounce back up during the test period of 2015 – 2016. Averages of analysts' forecasts of rates for long-term Treasury securities, Aaa bonds and Baa bonds for this test period are 4.41%, 5.20% and 5.95%, 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 three quantitative studies which found ERPs are much higher today than in the past. The first is an analysis I prepared using data predicted by Value Line for its Industrial Composite. The second study was reported by Bank of America Merrill Lynch in 2012. The third is a study prepared by researchers at the Federal Reserve Bank of New York in May 2013.

Q. Why is this evidence important?

A. It is important because it shows costs of equity have not dropped nearly as much as the decrease in interest rates. All of the 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 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 945 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 42 DCF analyses reported in PGE Exhibit 1203 using data determined by Value Line for the IC during the period 1984 to 2013. To compute growth rates, I averaged Value Line's forecasts of 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 period 2008-2013, however, the indicated average expected equity risk premium was 8.97%. This estimate of 8.97% 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. See PGE Exhibit 1217. 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 a structurally higher risk premium 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 ERP to compensate for this unprecedented level of earnings risk. With a forecasted rate for AAA bonds of 5.2% (See PGE Exhibit 1202 and PGE Exhibit 1211), the implied expected market return is 13.2% and the indicated market risk premium with a forecasted rate for Treasuries of 4.41% is 8.79%, very close to the market risk premium of 8.97% estimated in PGE Exhibit 1203.

Q. What did researchers at the Federal Reserve Bank of New York Bank find?

A. On May 8, 2013, researchers at the Federal Reserve Bank of New York published a report called "Are Stocks Cheap? A Review of the Evidence". Their analysis was based on a weighted average of 29 models for the period 1962 to 2012. They found the ERP for December 2012 was "about as high as it's ever been" and "the risk premium today is high irrespective of investment horizon" whereas earlier high risk premiums in 1974 and 2009 were limited to short horizons. The results of this Federal Reserve Bank of New York analysis is consistent with my study based on data for the Value Line Industrial Composite and the 2012 Bank of America Merrill Lynch analysis just discussed. All three of these studies indicate investors currently require higher risk premiums for equity investments than the long-term average.

Q. What do these studies indicate about changes in the cost of equity that have occurred

in the last few years?

A. All of the 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 now available to most utilities in the benchmark sample. Mr. Hager, Mr. Valach and Mr. Greene point out that PGE is more risky due to a number of factors that make it more risky than other electric utilities. One factor is its Power Cost Adjustment Mechanism (PCAM) does not fully offset large unexpected increases in operating costs from replacing power when wind and hydro resources produce less output than expected. Also, uncertain weather may impact demand as well as supply of power. Mr. Hager, Mr. Valach and Mr. Greene also point out bond rating agencies impute debt to PGE for its relatively large purchased power contracts and other factors which increase risk.

I present quantitative evidence in section II which shows the net impact of these factors and other factors I mention increases PGE's cost of equity and RROE. This evidence includes PGE has a weak PCAM, has a higher beta and has had authorized ROEs that have averaged 50 basis points less than the average of authorized ROEs for the sample I use to determine benchmark costs of equity.

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 my 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 rates of return on equity and earned ROEs as well as authorized ROEs reported by AUS Utility Reports 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.

Q. Have you prepared any exhibits to accompany your testimony?

A. Yes. I have prepared 17 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 <u>Bluefield Waterworks</u> 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 <u>Hope Natural Gas Company</u> 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 <u>Duquesne Light Co. v Barasch</u> 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. Additional risk faced by PGE should be recognized when setting the fair rate for 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. Hager, Mr. Valach, Mr. Greene and me indicate PGE's RROE is higher than the average ROE required by the utilities in my benchmark sample.

Q. What is ORS 756.040?

A. In Oregon, the legislature passed ORS 756.040, which puts into state law the principles the U.S. Supreme Court established in the <u>Hope</u> and <u>Bluefield</u> decisions.

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 will ultimately fall 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 for the various reasons discussed in Section II of my testimony and in the testimony of Mr. Valach, Mr. Greene and Mr. Hager.
   - S&P advises investors that PGE has a weak PCAM which makes the Company more risky due to 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 because it has consistently been authorized ROEs below the average authorized for utilities in my DCF sample.
- It has higher market risk as measured by beta than the average utility in the sample I adopted to make DCF cost of equity estimates.
- It may be less risky due to decoupling, but a recent Brattle Group study presents statistical estimates that question that conclusion. Also, any benefits of decoupling are largely in the DCF cost of equity estimates because most of the utilities have some form of decoupling.

2. The benchmark cost of common equity for the electric utilities samples I use to determine guideline equity costs falls in a range of 9.9% to 10.6% at this time with a mid-point estimate of 10.3%:
   - Three DCF estimates for the electric utilities sample indicate the cost of equity falls in a range of 9.6% to 9.9%;
   - 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 10.2% to 11.4%;
   - Averages of earned ROEs for the sample of 10.2%, authorized ROEs of 10.4% and Value Line forecasts of future ROEs of 10.6% corroborate the reasonableness of my cost of equity estimates.

3. I conclude that PGE's RROE falls above 10.3%, the mid-point of the range of costs of equity estimated for the sample, conclude an authorized ROE of 10.5% is reasonable for PGE. The Company's requested ROE of 10.0% falls within the cost of equity range I estimate for my benchmark sample of utilities but is conservative. 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 and PGE Exhibit 1215.

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 51 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 four 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, 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.

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 greater risk than the average utility in the sample. The Commission has recognized PGE is more risky because it has significant exposure to the wholesale market. Unexpected changes in output from wind and hydro projects that are beyond the control of PGE create this risk. PGE has a PCAM but S&P advises investors that this mechanism is weak (S&P, RatingsDirect, June 4, 2013). Its PCAM mitigates, but does not fully offset, unexpected expenses because of its large dead bands and an earnings test that precludes full recovery of unexpected power costs. Mr. Hager, Mr. Valach and Mr. Greene discuss several other risks in their testimony that I do not repeat here.

I focus on quantitative evidence that PGE is more risky than the sample used to determine DCF estimates: It has a beta that is above the sample average and, during the last five years, PGE has consistently had an authorized ROE below the average ROE authorized for the benchmark sample. The Commission has found these risks are offset to some extent by PGE having decoupling.

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 10 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, Mr. Greene and Mr. Hager also address this issue. S&P and other ratings agencies impute debt to PGE to reflect its purchased power contracts. This has the result of increasing PGE's leverage for ratings purposes and thus could have a negative impact on PGE's credit rating.

Q. Turn to the quantitative evidence showing PGE is more risky. 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 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 risk, PGE is more risky than the average of my utility sample. The beta for PGE is .75 while the median average beta for the sample is .70.

Q. How does the five-year average of PGE's authorized ROEs compare to the average of authorized ROEs for the other 19 utilities in your DCF sample during this period?

A. It has been 50 basis points lower. During the period 2008 to 2012, the average of authorized ROEs for the other 19 utilities in the sample was 10.54% while PGE had an average of authorized ROEs of only 10.04%. See PGE Exhibit 1204. Everything else the same, PGE's lower authorized ROE reduces the chance it will earn as high an ROE as the ROE achieved by utilities in my benchmark sample. To the extent the past history revealed in PGE Exhibit 1204 continues, it indicates to investors that PGE has less of a chance to earn the opportunity cost of equity and thus this evidence also indicates PGE would be viewed by investors as being more risky than the sample.

Q. Do you have any comments about the impact of decoupling on the need for a risk premium?

A. Yes. In Order 09-020, the Commission found that adoption of decoupling justified an ROE reduction of 10 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 conservation efforts. I have two primary observations.

First, though investor services view decoupling mechanisms as credit positive for utilities, 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 <u>already</u> in the benchmark costs of equity estimates. PGE Exhibit 1201 shows 18 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 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 conservation initiatives are pressed by environmental activists, government agencies and utilities. An 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 thus reduced the net cost of capital. Their robust statistical tests did not 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.

In summary, I do not dismiss the Commission's prior determination that decoupling may reduce PGE's risk, but take into account recent quantitative evidence indicating the net benefit of decoupling is questionable and, if there is a net benefit, it is probably already reflected in the cost of equity estimates for my sample.

Q. What is your recommended risk adjustment for PGE?

A. I find PGE has a RROE that is 20 basis points higher than the estimated cost of equity for my sample of 20 utilities.

In Order No. 07-015, the Commission determined that PGE requires a risk premium of 10 basis points to compensate for its significant exposure to the wholesale market. That risk continues due to uncertainty of recovering unexpected power costs using the weak PCAM available to PGE. PGE is also more risky due to the factors discussed by Mr. Valach, Mr. Hager and Mr. Greene which I do not repeat in this testimony. Quantitative evidence indicates PGE is more risky than the sample. It has a higher beta than the average for the sample, has had lower authorized ROEs than the other sample utilities and has a weak PCAM.

I determined the mid-point of my estimates of the cost of equity for the sample is 10.3%. Taking into account PGE's exposure to all of the 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 and has an indicated RROE of 10.5%.

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. I begin my RROE study with DCF estimates based on three different versions of the DCF model. 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. 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, risk premium ("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 the DCF models. If the equity costs produced with DCF models 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 given little weight.

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 earnings per share ("EPS") growth and analysts' forecasts of EPS growth reported by Zacks, Yahoo! Finance and Reuters and finds the benchmark cost of equity is 9.6%. 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 9.6%. 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 9.9% 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"). Staff of the Division of Ratepayer Advocates at the California PUC[1] and other analysts estimate D_1 with formula (1):

(1) $$\text{Equity Cost} = D_0/P_0 \times (1 + g) + g,$$

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. I adopt this method of determining D_1 and use formula (2) to implement the model:

(2) $$\text{Equity Cost} = D_1/P_0 + g.$$

The constant growth DCF model and multistage DCF models are derived from the valuation

[1] For example, Division of Ratepayer Advocates, Report of the Cost of Capital for San Jose Water Company dated, Docket A: 06-02-014, dated June 2006

models shown in equations (3) and (4) 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, . . . D_∞ 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, dividends per share ("DPS"), earnings per share (" 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 multistage 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. Estimates of both the current yields (D_0/P_0) and the expected yields 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, 2013 to November 30, 2013. All estimates of dividend yields are adjusted for the time value of money.

Q. Why have you adjusted the values for D_1/P_0 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 because all of the utilities in the sample are projected to have positive growth in the future. I recognize that potential positive growth by adopting an average of analysts' forecasts and Value Line's forecasts of EPS for the respective utilities. This approach recognizes dividend growth ultimately depends on growth in earnings. A general discussion of the various approaches that could be taken is provided in Roger Morin, *New Regulatory Finance,* pages 343-349.

Q. What data did you use to determine your estimates of growth?

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 5.3% 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 expected 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 the expected return on investment grade debt. 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. Consistent with that common sense conclusion, the Federal Energy Regulatory Commission ("FERC") found a cost of equity estimate that is less than 100 basis points above the cost of investment grade bonds is not credible. 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 is appropriate to eliminate the cost of equity estimate for IDACORP. Once that is done, the average cost of equity estimate for the remaining 19 utilities is 9.6%. 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.

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") used in a number of cases to determine long-term GDP growth one would expect investors to rely upon[2]. This method assumes an

[2]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, 2012

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[3]. Generally, estimates of future GDP growth reported by Federal agencies and reported by Blue Chip are for periods that start before 2024 (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 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)[4] 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 assume terminal GDP growth expected by investors will be lower than it has been in the past. Specifically, I assume future GDP growth will be 6.0% which is less than the average growth in GDP that occurred in the past.

Q. What are the results of your two-stage DCF analysis?

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[3] 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.

[4] For example, the December 1, 2013 Blue Chip long-term forecast of GDP goes out no further than the five-year period 2020-2024 and the November 22, 2013 Value Line Quarterly forecast goes out no further than 2017.

A. The results are reported in PGE Exhibit 1209. The average of the high and low equity cost estimates is 9.6%.

Q. Please describe your third DCF analysis.

A. My third DCF analysis is developed in PGE Exhibit 1210. This analysis determines the costs of equity for the various utilities by finding internal rates of return that are consistent with different growth rates in three stages. Initially it is assumed that an average of recent prices (“P_{2013}”) and my forecasts of dividends for 2014 are appropriate for the analysis. Growth rates adopted for the first stage (for 2015-2019, 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_{2015} and D_{2019}) 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 (2020 to 2029). PGE Exhibit 1210 reports the first and last forecasted cash distributions for this period (D_{2020} and $(P+D)_{2029}$) for each utility. The terminal growth rate is assumed to be GDP growth of 6.0% which I discussed above. In 2029 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 9.9% and thus the indicated cost of equity for PGE is above 9.9%.

Q. Do you have any evidence which indicates your estimated DCF range may be conservative at this time?

A. Yes. Some analysts determine estimates of future growth based on growth determined from Value Line forecasts of future ROEs and forecasted retention ratios. With this approach, usually called the "sustainable growth" approach, the growth rate g is found as follows:

$$g = br + sv,$$

where b is the forecasted retention ratio, r is the Value Line forecast of the expected ROE (put on a mid-year basis), and sv growth is an estimate of future growth expected from future sales of common stock. Roger Morin points out that one of the practical problems with applying this approach is potential circularity in the argument.[5] This circularity occurs because Value Line's estimates of the expected future ROEs depend to a large extent upon what regulators set as the authorized ROEs.

Q. What is the implication of this potential circularity?

A. The implication is that if one relies on Value Line forecasts of expected future ROEs to determine growth for the DCF estimates, the analyst might just as well adopt the Value Line forecasts of ROEs (after adjustment to a mid-period basis) as another indicator of the fair rate of return on equity for the sample utilities.

Q. How does the average of Value Line forecasts of ROEs for your electricity sample compare to your DCF estimates?

[5] Morin's discussion of practical problems with the sustainable growth method is presented at pages 306-307. See Morin, *New Regulatory Finance*, pages 303, 306 and 307.

A. It is higher. The average of Value Line forecasts of future ROEs is 10.6%. See PGE Exhibit 1215. This comparison suggests the DCF model produces conservative estimates of the cost of equity at this time.

IV. Risk Premium (RP) Equity Cost Estimates

Q. Please turn to your RP 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 10.2% to 11.4%. 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 2015 – 2016.

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 2011, that annual average dropped to 3.91% and dropped below 3.0% in 2012, based on fears of a second recession and actions the Federal Reserve took to stimulate economic recovery. In November 2013, 30-year Treasury rates averaged 3.8% and are expected to bounce back up in 2015 – 2016. An average of estimates made by analysts which were reported in December 2013 by Blue Chip is 4.50%, the comparable forecast made by Value Line in November is 4.35% and the average of forecasts reported by Global Insight in November 2013 is 4.39%[6]. For my analyses, I have relied upon the average of all three forecasts which is 4.41%. See PGE Exhibit 1211.

Q. Why have you used the period 2015-2016 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 2015. I do not know when PGE will file for different rates but recognize the new rates set for 2015 may be in effect for more than one year. As a result, I have adopted the period 2015-2016 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 2015-2016 of 4.41% is higher than rates are currently, but lower than Treasury security rates were during most years used to determine historical relationships between Treasury

[6] The average forecast reported by Global Insight in January 2014 is higher than the one reported in November, but I have use the November forecast in my analysis to be consistent.

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").

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, the California PUC 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 PUC Division of Ratepayer Advocates ("DRA") Staff to determine costs of equity.[7] 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.[8] 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?

A. This risk premium analysis indicates the estimated future average cost of equity for the electric utilities falls in a range of 10.2% to 11.4%. 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

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[7] For example, see Division of Ratepayer Advocates, California PUC Report on the Cost of Capital, San Jose Water June 2006, Application 06-02-014.

[8] If Value Line revised the reported average, I relied on the most recent ROE reported.

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 more recent 5-year period. The results of this analysis are reported in PGE Exhibit 1212. Forecasts of 30-year Treasury bond rates expected in 2015 to 2016 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 provides 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 2012. It is based on data for the Moody's index through 2000 and an index of eight electric utilities that did not cut dividends during the period 2000 to 2012.

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 4.41% that is expected in 2015-2016 is lower than the average Treasury rate of 6.15% for the period 1950 to 2012 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 Decision 02-11-027 I discussed above. Based on these estimates, the benchmark equity cost range is 10.8% to 11.2% and the indicated cost of equity for PGE is above the middle of that range. See PGE Exhibit 1213 and PGE Exhibit 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).

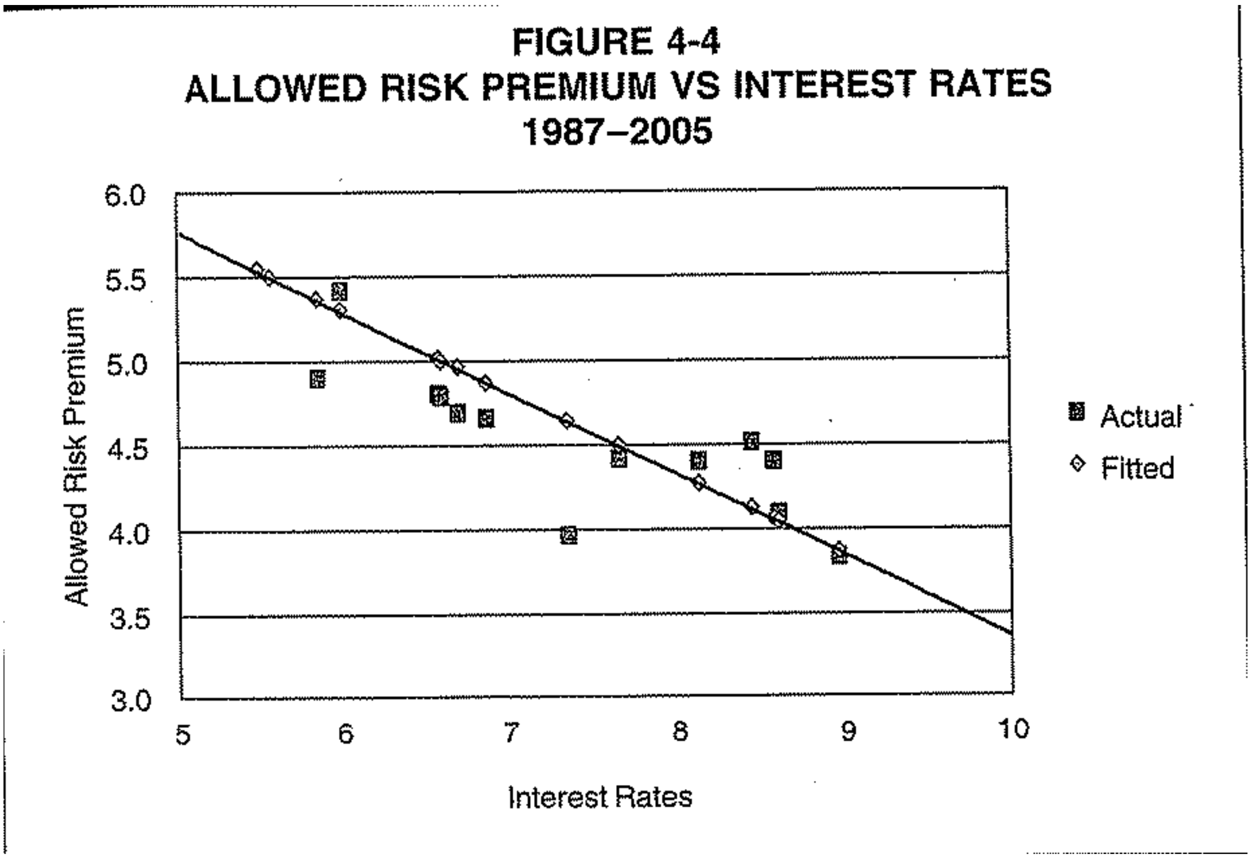
Q. Please discuss Dr. Morin's approach.

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:

$$(5) \qquad RPm = 8.2049 - 0.4833 \text{ x Yield}$$

where averages of allowed equity returns reported by Regulatory Research Associates are adopted as annual proxies for costs of equity. 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:



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 10.4% in 2015 - 2016. As PGE is more risky than the typical electric utility, this model indicates the Company has a RROE higher than 10.4%.

Q. Has your statistical analysis been checked and validated by Staff at a regulatory commission?

A. Yes. I presented an earlier version of this analysis in Application 12-02-013 (Bear Valley Electric Service) in 2012. Staff of the Division of Ratepayer Advocates of the California Public Utility Commission used its own software and replicated my results. Using the results of their validation of my model and a forecast of Treasury rates of 4.43%, DRA agreed the indicated cost of equity for a typical electric utility would be 10.32%, a value close to the mid-point of the range I estimate in this case.[9]

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 4.41% from PGE Exhibit 1211 in the formula estimated by Dr. Morin indicates a risk premium equity cost estimate for a typical electric utility of 10.5%. Applying Dr. Morin's result indicates that my analysis provides a conservative estimate of the cost of equity.

[9] DRA Opening Brief. Dated December 13, 2013 at page 222.

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 did. The data in PGE Exhibit 1215 provide such checks.

Q. Does PGE Exhibit 1215 provide additional information and perspective about what is a fair ROE for PGE?

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 sample of 19 other electric utilities in PGE Exhibit 1201.

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. PGE is more risky than the average of the other utilities in the sample thus these data provide information about the minimum ROE that should be authorized for PGE.

PGE Exhibit 1215 provides a list of earned ROEs in 2012 reported by Value Line 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 expected cost of investment grade debt plus

100 basis points[10]. Avista, Great Plains Energy and PNM Resources earned only 6.2%, 5.9% and 6.6%, respectively, during 2012. These ROEs are clearly below any reasonable measure of the current cost of equity and should be disregarded. Once those earned returns are 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. 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.

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

[10] As discussed above, the FERC has determined a reasonable cost of equity estimate is 100 basis points higher than the cost of investment grade debt.

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 what ROEs are expected to be authorized and how well the various utilities are expected to perform in the future. Thus the forecasted ROES 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 range of averages of authorized returns, realized ROEs and forecasted ROEs reported in PGE Exhibit 1215 provide a gauge indicating the equity cost range of 9.9% to 10.6% for the sample which I present in PGE Exhibit 1216 is 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. Greene, Mr. Hager, and me. PGE continues to require a risk adjustment of 10 basis points to compensate for its exposure to the wholesale market. This exposure is not offset by its weak PCAM. Once decoupling and other risk factors are considered, on net, I determined PGE has an RROE that is 20 basis points higher than the 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 9.6% 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 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 9.6%. 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 9.9%.

Data reported in PGE Exhibit 1215 indicate the DCF estimates provide conservative indicators of the fair ROE for PGE at this time.

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, 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 an ROE range of 10.2% to 11.4% for the sample of 20 electric utilities.

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 a risk adjustment 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 the cost of equity range for the sample is 9.9% to 10.6%, the mid-point of that cost of equity range is 10.3% and the indicated cost of equity for PGE is 10.5%. See PGE Exhibit 1216.

Q. Is PGE'S requested ROE of 10.0% reasonable?

A. Yes, it is. A 10.0% ROE falls within the cost of equity range I estimate for my sample but is below the mid-point of that range for the sample of 10.3%. I estimate PGE is more risky than the average utility in that sample and thus the Company's request for a 10% ROE is conservative and reasonable.

VII Qualifications of Thomas M. Zepp

Q. What is your profession and background?

A. I am an economist and principal of Zepp Consulting LLC. I am also a 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 URI 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 and 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 testimony?

A. Yes.

List of Exhibits

Portland General Electric

Table 1 (page 1)

Comparison of PGE to the DCF Electric Utilities Sample

			Value Line Betas[c/]	Expected Common Equity Ratio[c/]	S&P Bond Rating[a/]	Moody's Bond Rating[a/]
1	ALLETE	ALE	0.70	57%	A-	A2
2	Alliant Energy	LNT	0.75	52%	A-	A3
3	Avista	AVA	0.70	52%	A-	A3
4	Black Hills Corporation	BKH	0.85	49%	BBB	Baa1/Baa2
5	CLECO Corporation	CNL	0.65	64%	BBB/BBB-	Baa2/Baa3
6	CMS Energy	CMS	0.75	38%	BBB+/BBB	Baa1
7	Great Plains Energy	GXP	0.80	52%	BBB	Baa2
8	Hawaiian Electric	HE	0.70	51%	BBB-	Baa2
9	IDACORP	IDA	0.70	53%	A-	A2
10	MGE Energy, Inc.	MGEE	0.60	64%	AA-	Aa2
11	Northwestern Corp	NWE	0.70	54%	NR	Baa1
12	OGE Energy	OGE	0.75	57%	BBB+	Baa1
13	Pinnacle West	PNW	0.70	60%	BBB	Baa1
14	PNM Resources, Inc.	PNM	0.90	49%	BBB	Baa3
15	Portland General Electric	POR	0.75	51%	A-	A2
16	SCANA	SCG	0.70	47%	BBB+	Baa1/Baa2
17	TECO	TE	0.95	44%	BBB+/BBB	A3
18	UNS Energy	UNS	0.70	37%	NR	Baa2
19	Westar	WR	0.75	50%	A-	A3
20	Wisconsin Energy	WEC	0.65	50%	A-/BBB+	A2/A3
	Average[b/]		0.70	51%	BBB+/A-	A3
	PGE[d/]		0.75	50%	A-	A1

Notes and Sources

a/ AUS Utility Reports, November 2013.
b/ Averages are medians.
c/ Value Line Investment Survey Issue 1 (dated November 22, 2013), Issue 5 (dated September 20, 2013) and Issue 11 (dated November 1, 2013).
d/ Data from the Company.

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Portland General Electric

Table 1 (page 2)

Comparison of PGE to the DCF Electric Utilities Sample

		Percentage of Electric Revenues[a]	Market Capitalization[a,e] ($ millions)	Decoupling Available in at Least One State[f]	Percentage of Purchased Power[c]
1	ALLETE	91%	$2,012	yes	16%
2	Alliant Energy	82%	$5,677	yes	na
3	Avista	63%	$1,646	yes	24%
4	Black Hills Corporation	51%	$2,261	yes[g]	61%
5	CLECO Corporation	95%	$2,810	yes[g]	10%
6	CMS Energy	64%	$7,264	no	52%
7	Great Plains Energy	100%	$3,558	no	9%
8	Hawaiian Electric	92%	$2,571	yes	42%
9	IDACORP	100%	$2,579	yes	21%
10	MGE Energy, Inc.	70%	$1,290	yes	41%
11	Northwestern Corp	75%	$1,949	yes[g]	na
12	OGE Energy	61%	$14,428	yes[g]	16%
13	Pinnacle West	100%	$6,262	yes[g]	19%
14	PNM Resources, Inc.	100%	$1,898	yes[g,i]	0%
15	Portland General Electric	100%	$2,248	yes	55%
16	SCANA	56%	$6,507	yes[g,h]	2%
17	TECO	66%	$3,731	yes[h]	6%
18	UNS Energy	91%	$2,037	yes[g]	17%
19	Westar	100%	$3,978	yes[g]	0%
20	Wisconsin Energy	74%	$9,497	yes	37%
	Average[d]	87%	$2,695		18%
	Portland General Electric	100%	$2,248	yes	55%

Notes and Sources (continued)

e/ Market Capitalization as of October 17, 2013.
f/ Source: IEE, State Energy Efficiency Regulatory Frameworks, Summary Table, July 2013.
g/ Fixed cost recovery provided by a Lost Revenue Adjustment Mechanism instead of decoupling.
h/ Decoupling for gas only.
i/ Pending in Texas.

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PGE/average	83.42%	305.56%

Portland General Electric

Table 2

Past, Current and Forecasted Rates for Treasury Securities , Aaa Bonds and Baa Bonds

A. Past Actual Rates (1980 to 2012)[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%
2012	2.92%	3.67%	4.94%
Average	7.17%	7.99%	9.12%
B. Current rates[b/]	3.82%	4.62%	5.36%
C. Expected rates[c/]	4.41%	5.20%	5.95%

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 26, 2013.
c/ Averages of rates expected in 2015 to 2016. See Table 11.

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Portland General Electric

Table 3

Determination of Average Risk Premiums Based on DCF Analyses of the Value Line Industrial Composite: 1984 to 2013

	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%
42	2/13	2.00%	8.98%	10.98%	3.08%	7.90%

Averages for:	
All years (1987-2013)	6.53%
Recent past (2008-2013)	8.97%

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Portland General Electric

Table 4

Comparison of Authorized ROEs for PGE and the Sample Utilities

	2008	2009	2010	2011	2012	5-Year Average
ALLETE, Inc.	11.60%	10.74%	10.38%	10.38%	10.38%	10.70%
Alliant Energy Corporation	11.02%	11.02%	10.41%	10.34%	10.34%	10.63%
Avista Corporation	10.25%	10.40%	10.33%	10.33%	9.98%	10.26%
Black Hills	10.75%	10.71%	10.64%	10.72%	10.72%	10.71%
Cleco Corporation	11.25%	10.70%	10.70%	10.70%	10.70%	10.81%
CMS Energy Corporation	10.93%	10.93%	10.63%	10.60%	10.30%	10.68%
Great Plains Energy	10.45%	10.45%	10.45%	10.25%	10.12%	10.34%
Hawaiian Electric Industries	10.82%	10.82%	10.70%	10.47%	9.67%	10.50%
IDACORP	10.50%	10.50%	10.18%	10.18%	10.18%	10.34%
MGE Energy, Inc.	10.80%	10.80%	10.40%	10.30%	10.30%	10.52%
Northwestern Corporation	11.11%	11.11%	11.11%	10.90%	10.83%	11.01%
OGE Energy Corp.	10.38%	10.13%	10.13%	9.98%	9.98%	10.12%
Pinnacle West Capital Corp.	10.75%	10.75%	11.00%	11.00%	11.00%	10.88%
PNM Resources	10.28%	10.38%	10.38%	10.22%	10.22%	10.32%
SCANA	10.67%	10.67%	10.67%	10.72%	10.72%	10.69%
TECO Energy, Inc.	11.25%	11.00%	11.00%	11.00%	11.00%	11.05%
UNS Energy	10.34%	10.13%	9.88%	9.88%	9.92%	10.03%
Westar Energy, Inc.	10.00%	10.00%	10.20%	10.20%	10.20%	10.12%
Wisconsin Energy	10.75%	10.75%	10.38%	10.38%	10.43%	10.54%
Average for 19 Utilities	10.73%	10.63%	10.50%	10.45%	10.37%	10.54%
Portland General Electric	10.10%	10.00%	10.10%	10.00%	10.00%	10.04%
Difference						0.50%

Notes and Sources:

a/ 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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Table 5

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	1.03%
	Low-Cap Companies[c/]	1.26	1.63%
	Micro-Cap Companies[d/]	1.51	2.80%
2.	Evidence Published in Zepp Article[e/]		0.99%

Notes and Sources:

a/ Data from Table 7-12 of Morningstar 2013 SBBI Valuation Edition Yearbook, page 96.
b/ Companies with market capitalization between $1,909 million and $7,687 million included in the Morningstar 2013 study. Large-Cap is above $7,687 million.
c/ Companies with market capitalization between $514 million and $1,909 million. included in the Morningstar 2013 study.
d/ Companies with market capitalization less than $514 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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Table 6

Averages of Current Dividend Yields (D_0/P_0) and Expected Dividend Yields (D_1/P_0) for the Electric Utilities Sample for the 3-Month Period Ending November 2013[a]

		Current (D_0/P_0)	Expected[b] (D_1/P_0)
1	ALLETE	4.06%	4.32%
2	Alliant Energy	3.84%	4.05%
3	Avista	4.71%	4.92%
4	Black Hills Corporation	3.13%	3.37%
5	CLECO Corporation	3.29%	3.48%
6	CMS Energy	3.92%	4.15%
7	Great Plains Energy	4.14%	4.38%
8	Hawaiian Electric	5.03%	5.19%
9	IDACORP	3.64%	3.75%
10	MGE Energy, Inc.	3.15%	3.30%
11	Northwestern Corp	3.66%	3.85%
12	OGE Energy	2.36%	2.48%
13	Pinnacle West	4.27%	4.47%
14	PNM Resources, Inc.	3.02%	3.30%
15	Portland General Electric	3.97%	4.16%
16	SCANA	4.51%	4.72%
17	TECO	5.39%	5.57%
18	UNS Energy	3.85%	4.12%
19	Westar	4.53%	4.72%
20	Wisconsin Energy	3.86%	4.06%
	Average	3.92%	4.12%

Source:
_a/ For the period ending November 30, 2013. Yields are adjusted for time value of money.
b/ Current dividend yields increased by the respective estimated average growth rates reported in Table 7.

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Table 7

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	7.0	6.0	6.0	6.0	6.0	6.5
2	Alliant Energy	6.0	4.8	5.3	5.4	5.2	5.6
3	Avista	4.0	5.0	5.0	5.0	5.0	4.5
4	Black Hills Corporation	11.5	4.0	4.0	4.0	4.0	7.8
5	CLECO Corporation	5.5	8.0	8.0	2.7	6.2	5.9
6	CMS Energy	5.5	6.1	6.1	6.1	6.1	5.8
7	Great Plains Energy	6.5	7.0	6.9	1.6	5.2	5.8
8	Hawaiian Electric	3.5	2.5	2.3	3.8	2.9	3.2
9	IDACORP	2.0	4.0	4.0	na	4.0	3.0
10	MGE Energy, Inc.	5.5	4.0	na	na	4.0	4.8
11	Northwestern Corp	4.5	7.0	5.0	7.0	6.3	5.4
12	OGE Energy	5.0	5.0	6.0	5.0	5.3	5.2
13	Pinnacle West	5.0	4.7	4.5	4.7	4.6	4.8
14	PNM Resources, Inc.	12.0	6.4	7.8	6.4	6.9	9.4
15	Portland General Electric	3.5	6.5	5.5	6.2	6.1	4.8
16	SCANA	4.5	4.6	4.4	4.7	4.6	4.5
17	TECO	3.0	2.7	5.0	3.3	3.7	3.3
18	UNS Energy	6.5	8.0	7.0	na	7.5	7.0
19	Westar	6.0	1.0	3.7	2.0	2.2	4.1
20	Wisconsin Energy	5.5	5.2	5.4	5.2	5.3	5.4
	Average	5.6				5.0	5.3

Notes and Sources:

a/ Value Line Investment Survey Issue 1 (dated November 22, 2013), Issue 5 (dated September 20, 2013) and Issue 11 (dated November 1, 2013).

b/ Sources are analysts' forecasts reported on the Internet on December 3, 2013.

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Table 8

Constant Growth DCF Cost of Equity Estimates

		3-Month Average D_1/P_0 [a/]	Average of Forecasts of Growth [b/]	Equity Cost Estimates [c/]	
1	ALLETE	4.32%	6.50%	10.8%	
2	Alliant Energy	4.05%	5.58%	9.6%	
3	Avista	4.92%	4.50%	9.4%	
4	Black Hills Corporation	3.37%	7.75%	11.1%	
5	CLECO Corporation	3.48%	5.87%	9.4%	
6	CMS Energy	4.15%	5.79%	9.9%	
7	Great Plains Energy	4.38%	5.84%	10.2%	
8	Hawaiian Electric	5.19%	3.18%	8.4%	
9	IDACORP	3.75%	3.00%	6.8%	[d/]
10	MGE Energy, Inc.	3.30%	4.75%	8.1%	
11	Northwestern Corp	3.85%	5.42%	9.3%	
12	OGE Energy	2.48%	5.17%	7.6%	
13	Pinnacle West	4.47%	4.80%	9.3%	
14	PNM Resources, Inc.	3.30%	9.44%	12.7%	
15	Portland General Electric	4.16%	4.78%	8.9%	
16	SCANA	4.72%	4.54%	9.3%	
17	TECO	5.57%	3.34%	8.9%	
18	UNS Energy	4.12%	7.00%	11.1%	
19	Westar	4.72%	4.11%	8.8%	
20	Wisconsin Energy	4.06%	5.39%	9.5%	
	Average			9.6%	

Notes and Sources:

a/ The 3-month averages of expected yields (D_1/P_0) reported in Table 6.

b/ Average of Value Line and analysts' forecasts reported in Table 7.

c/ ROE = $D_1/P_0 + g$

d/ Not included in average. It is less than 100 basis points above expected cost of Baa bonds. See Table 11 for expecged cost of Baa bonds.

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Table 9

Application of the FERC Two-Step 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	4.32%	6.00%	10.32%	6.67%	10.99%
2	Alliant Energy	4.05%	5.20%	9.25%	6.00%	10.05%
3	Avista	4.92%	4.66%	9.58%	5.33%	10.25%
4	Black Hills Corporation	3.37%	4.66%	8.03%	9.69%	13.05%
5	CLECO Corporation	3.48%	3.81%	7.29%	7.34%	10.82%
6	CMS Energy	4.15%	5.67%	9.82%	6.07%	10.22%
7	Great Plains Energy	4.38%	3.08%	7.46%	6.67%	11.05%
8	Hawaiian Electric	5.19%	3.52%	8.71%	4.49%	9.68%
9	IDACORP	3.75%	3.32%	7.07%	4.66%	8.41%
10	MGE Energy, Inc.	3.30%	4.66%	7.96%	5.67%	8.97%
11	Northwestern Corp	3.85%	5.00%	8.85%	6.67%	10.52%
12	OGE Energy	2.48%	5.33%	7.81%	6.00%	8.48%
13	Pinnacle West	4.47%	5.00%	9.47%	5.33%	9.80%
14	PNM Resources, Inc.	3.30%	6.29%	9.59%	10.02%	13.32%
15	Portland General Electric	4.16%	4.33%	8.49%	6.30%	10.47%
16	SCANA	4.72%	4.93%	9.65%	5.15%	9.87%
17	TECO	5.57%	3.80%	9.38%	5.33%	10.90%
18	UNS Energy	4.12%	6.34%	10.45%	7.34%	11.46%
19	Westar	4.72%	2.65%	7.36%	6.00%	10.72%
20	Wisconsin Energy	4.06%	5.47%	9.53%	5.67%	9.73%

Average of high and low equity cost estimates 9.6%

Sources and Notes:

a/ Use FERC method of assigning a weight of two-thirds to average EPS growth rates reported in Table 4 and one-third to a forecast of future GDP growth of 6.0%.

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Table 10

Three Stage DCF Analysis

		Internal Rate of Return	P_{2013}	First Year Dividend D_1 [a] D_{2014}	Stage 1 [a] D_{2015}	D_{2019}	Stage 2 and 3 [b,c] D_{2020}	D_{2021}	D_{2028}	$(P+D)_{2029}$	P_{2029} [c]
1	ALLETE	10.5%	-$48.75	$2.10	$2.23	$2.87	$3.06	$3.26	$4.96	$130.21	$124.95
2	Alliant Energy	9.9%	-$50.93	$2.06	$2.17	$2.70	$2.85	$3.01	$4.48	$133.25	$128.50
3	Avista	10.4%	-$26.91	$1.32	$1.38	$1.65	$1.72	$1.81	$2.61	$69.25	$66.48
4	Black Hills Corporation	9.8%	-$50.73	$1.70	$1.83	$2.47	$2.65	$2.85	$4.49	$137.06	$132.31
5	CLECO Corporation	9.4%	-$45.74	$1.59	$1.68	$2.11	$2.24	$2.37	$3.55	$119.75	$115.98
6	CMS Energy	10.1%	-$27.02	$1.12	$1.18	$1.48	$1.57	$1.66	$2.48	$71.02	$68.39
7	Great Plains Energy	10.3%	-$23.17	$1.01	$1.07	$1.34	$1.42	$1.50	$2.25	$61.08	$58.69
8	Hawaiian Electric	10.2%	-$25.64	$1.33	$1.37	$1.55	$1.60	$1.66	$2.32	$64.26	$61.80
9	IDACORP	9.0%	-$49.23	$1.84	$1.89	$2.13	$2.20	$2.28	$3.16	$123.35	$119.99
10	MGE Energy, Inc.	9.0%	-$53.95	$1.77	$1.86	$2.24	$2.34	$2.46	$3.58	$138.59	$134.80
11	Northwestern Corp	9.7%	-$43.43	$1.66	$1.75	$2.16	$2.28	$2.41	$3.56	$113.11	$109.33
12	OGE Energy	8.3%	-$37.00	$0.91	$0.96	$1.17	$1.23	$1.30	$1.91	$94.85	$92.82
13	Pinnacle West	10.1%	-$55.37	$2.47	$2.59	$3.12	$3.27	$3.44	$5.01	$143.07	$137.76
14	PNM Resources, Inc.	10.2%	-$22.82	$0.75	$0.82	$1.18	$1.28	$1.40	$2.30	$63.64	$61.21
15	Portland General Electric	9.8%	-$28.75	$1.19	$1.25	$1.51	$1.58	$1.66	$2.42	$74.15	$71.59
16	SCANA	10.2%	-$46.67	$2.20	$2.30	$2.74	$2.87	$3.01	$4.36	$120.10	$115.49
17	TECO	10.6%	-$16.95	$0.94	$0.97	$1.11	$1.15	$1.20	$1.67	$42.62	$40.84
18	UNS Energy	10.4%	-$47.08	$1.93	$2.07	$2.71	$2.89	$3.09	$4.77	$126.76	$121.70
19	Westar	10.1%	-$31.18	$1.47	$1.53	$1.80	$1.87	$1.96	$2.80	$79.56	$76.59
20	Wisconsin Energy	9.9%	-$41.26	$1.67	$1.76	$2.18	$2.29	$2.42	$3.58	$107.57	$103.77
	Average	9.9%									

Notes and Sources:
a/ Assumes growwth is an average of Value Line and analysts' forecasts. See Table 6.
b/ Growth based on gradual transition from initial forecasts of EPS growth to expected long-term average GDP growth of 6.0%.
c/ Expected price received at end of stage 2.

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Table 11

Forecasts of Baa, Aaa and Long-term Treasury Securities Rates 2015 - 2016

	2015	2016	Average
Long-term Treasury Rates			
Blue Chip Consensus Forecasts[a/]	4.30%	4.70%	4.50%
Value Line[b/]	4.30%	4.40%	4.35%
Global Insight[c/]	4.19%	4.59%	4.39%
Overall Average			4.41%
Aaa Corporate Bonds			
Blue Chip Consensus Forecasts[a/]	4.90%	5.40%	5.15%
Value Line[b/]	5.20%	5.30%	5.25%
Global Insight[c/]	4.92%	5.48%	5.20%
Overall Average			5.20%
Baa Corporate Bonds			
Blue Chip Consensus Forecasts[a/]	5.90%	6.30%	6.10%
Global Insight[c/]	5.65%	5.94%	5.80%
Overall Average			5.95%

Sources and Notes:
a/ Blue Chip consensus forecasts published December 1, 2013.
b/ Value Line Quarterly forecasts dated November 22, 2013.
c/ IHS Global Insight, November, 2013.

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Table 12

Risk Premium Analysis: Proxies for Costs of Equity are Based on Method Used by Staff of California PUC Division 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	10.80%	3.91%	6.89%
	15-Year Average	5.06%	5.83%
	5-year Average	4.27%	6.99%
	Expected Long-term Treasury Bond Rate[d/]		4.41%
	Projected Returns on Equity for Sample		
	15-Year Average		10.2%
	5-Year Average		11.4%

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.
c/ As reported by the Federal Reserve or California DRA Staff.
d/ Source is Table 11.

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Table 13: Risk Premium Analysis Based on Holding Period Returns for Moody's Electric Utilities Sample as Updated, 1950 to 2012

	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%	$227.95	$8.65	0.38%	3.81%	4.19%	-1.39%
2002	4.84%	$219.63	$8.84	-3.65%	3.88%	0.22%	-5.53%
2003	5.11%	$247.54	$8.99	12.71%	4.09%	16.80%	11.96%
2004	4.84%	$289.86	$9.23	17.09%	3.73%	20.82%	15.71%
2005	4.61%	$302.10	$9.47	4.22%	3.27%	7.49%	2.65%
2006	4.91%	$343.43	$9.73	13.68%	3.22%	16.91%	12.30%
2007	4.50%	$319.74	$10.00	-6.90%	2.91%	-3.99%	-8.90%
2008	3.03%	$258.56	$10.40	-19.13%	3.25%	-15.88%	-20.38%

2009	4.58%	$297.39	$11.21	15.02%	4.34%	19.35%	16.32%
2010	4.14%	$350.40	$11.90	17.82%	4.00%	21.83%	17.25%
2011	2.48%	$379.14	$12.32	8.20%	3.51%	11.72%	7.58%
2012	2.41%	$416.77	$12.32	9.92%	3.25%	13.17%	10.69%

	Updated Study	Original Study
Average Treasury bond rate[a/]	6.15%	6.54%
Unadjusted average risk premium	5.54%	5.70%
Expected Treasury bond rate[c/]	4.41%	4.41%
Current risk premium[d/]	6.41%	6.77%
Estimated cost of equity for benchmark sample	10.8%	11.2%

Notes and Sources:

a/ Monthly rates for December of the indicated year. Morningstar, 2013 SBBI Valuation Yearbook, pages 198-199.

b/ Mergent, Moody's 2001 Public Utility Manual with updates for 2001-2010.

c/ Source is Table 11.

d/ As explained in testimony, adjustment assumes equity costs change by 50% as much as interest rates.

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Portland General Electric

Table 14

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]
10.4%	=	6.01%	+	4.41%

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 Table 11.
_c/ 6-month lag between order dates and Treasury bond rates adopted.

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Portland General Electric
Table 15
Earned, Authorized and Forecasted Returns on Common Equity

		ROEs Earned in 2012[c]		Authorized ROEs[a]	Forecasted ROE Estimates: Book Value Growth[c]	ROE Forecasted by Value Line[c]	Adjusted ROE Forecasts[d]
1	ALLETE	8.1%		10.4%	4.0%	10.0%	10.2%
2	Alliant Energy	10.3%		10.3%	4.0%	11.5%	11.7%
3	Avista	6.2%	[b]	10.0%	3.0%	8.5%	8.6%
4	Black Hills Corporation	7.1%		10.7%	3.0%	9.0%	9.1%
5	CLECO Corporation	10.9%		10.7%	5.0%	11.0%	11.3%
6	CMS Energy	12.9%		10.3%	5.5%	13.0%	13.3%
7	Great Plains Energy	5.9%	[b]	10.1%	2.5%	8.0%	8.1%
8	Hawaiian Electric	10.2%		9.7%	4.5%	8.0%	8.2%
9	IDACORP	9.6%		10.2%	4.5%	8.5%	8.7%
10	MGE Energy, Inc.	11.1%		10.3%	5.0%	11.5%	11.8%
11	Northwestern Corp	9.0%		10.8%	4.5%	9.5%	9.7%
12	OGE Energy	12.8%		10.0%	7.0%	12.0%	12.4%
13	Pinnacle West	9.8%		11.0%	3.5%	10.0%	10.2%
14	PNM Resources, Inc.	6.6%	[b]	10.2%	4.0%	9.0%	9.2%
15	Portland General Electric[e]	8.2%		10.0%	3.0%	8.0%	8.1%
16	SCANA	10.1%		10.7%	5.5%	9.5%	9.8%
17	TECO	10.7%		11.0%	1.2%	12.5%	12.6%
18	UNS Energy	8.5%		9.9%	5.0%	11.5%	11.8%
19	Westar Energy	9.4%		10.2%	5.0%	9.0%	9.2%
20	Wisconsin Energy	13.2%		10.4%	3.5%	14.5%	14.7%
	Average[e]	10.2%		10.4%	4.2%	10.3%	10.6%
	Portland General Electric	8.2%		10.0%	3.0%	8.0%	8.1%

Notes and Sources

a/ Reported by AUS Utilities Reports in November 2013.
b/ Not included in average because it is below the expected cost of investment grade debt plus 100 basis points.
c/ Value Line Investment Survey Issue 1 (dated November 22, 2013), Issue 5 (dated September 20, 2013) and Issue 11 (dated November 1, 2013).
d/ 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.
e/ PGE not included in averages.

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Portland General Electric

Table 16

Summary: Estimated Costs of Equity

	Estimated Range of Cost of Equity for Electric Utilities Samples		
DCF Analyses			
Constant Growth Model - Table 8		9.6%	
FERC Two-Step Model - Table 9		9.6%	
Three Stage Model - Table 10		9.9%	
Range of DCF estimates	9.6%	to	9.9%
Risk Premium Analyses			
California Staff Approach - Table 12	10.2%	to	11.4%
Realized Annual Returns - Table 13	10.8%	to	11.2%
Morin Statistical Approach -- Table 14		10.4%	
Range of RP estimates	10.2%	to	11.4%
Range of Forecasted, Earned and Authorized ROEs -- Table 15	10.2%	to	10.6%
Range of Equity Cost Estimates[a/]	9.9%	to	10.6%
Mid-point of equity cost range for sample		10.3%	
Indicated RROE for PGE		10.5%	

Notes:

a/ Averages of tops and bottoms of DCF and RP estimates.
b/ Average of top and mid-point of estimated costs of equity for sample.

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US Equity & US Quant Strategy in Pictures

US Strategy Overview

Equity and Quant Strategy | United States
16 February 2012

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S&P 500 2012 year-end target = 1350

- With the S&P currently trading near our year-end target, the market appears fairly value given the many macro risks we face in the second half (US policy, European recession, rising political tensions in the Middle East). We think the S&P is likely to remain within its two-year trading range (1000-1365), and thus we make no changes to our target at this time (see pg 19).
- Our year-end target is principally based on our earnings forecast, but we explicitly incorporate tactical, sentiment and technical models into our framework for a more multifaceted approach.

We assume a 50%+ higher equity risk premium vs. history

- We assume that macro headwinds and higher earnings volatility will keep the equity risk premium elevated through 2012.
- Our fair value target assumes a 650bp ERP (over 50% higher than the historical average of about 400bp).

S&P 500 EPS outlook: $104.50 for 2012

- We forecast a slowdown in EPS growth to 6% in 2012, just below the 1960-2010 EPS CAGR of 6.5%.
- Our 2012 estimate is below the bottom-up consensus forecast of $106 and reflects our more cautious outlook for companies with significant exposure to Europe, EM, US government and the consumer.

Sector preferences reflect a combination of growth, yield and quality; avoidance of beta

- **Overweight:** Consumer Staples, Technology
- **Marketweight:** Consumer Discretionary, Health Care, Industrials, Energy, Telecom, Utilities
- **Underweight:** Financials, Materials

Navigating a macro market: themes & views

Europe is expected to experience a mild recession this year, and in the US we face policy uncertainty and the presidential election. But even with high correlations and macro dominating the headlines, we believe fundamental analysis can still be rewarded. Our key themes and investment implications for 2012 are: 1) Pick your battles, 2) Lengthen your time horizon, 3) Yield and other cash deployment strategies, 4) Quality and 5) Growth.

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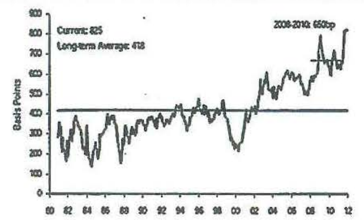
Chart 33: S&P 500 risk premium (DDM expected return less AAA corporate bond rate)

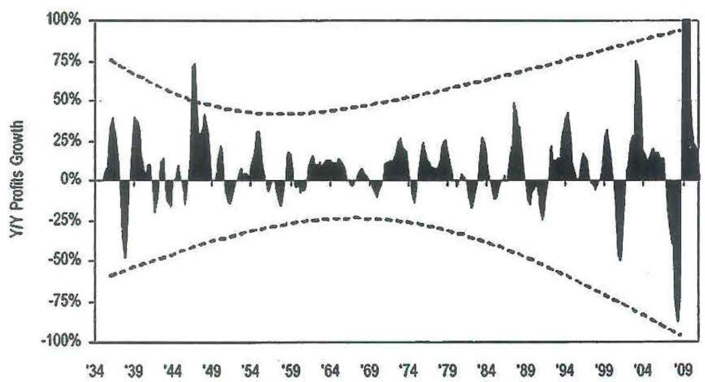


Source: BofA Merrill Lynch US Equity and US Quant Strategy

We assume a 50%+ higher equity risk premium vs. history

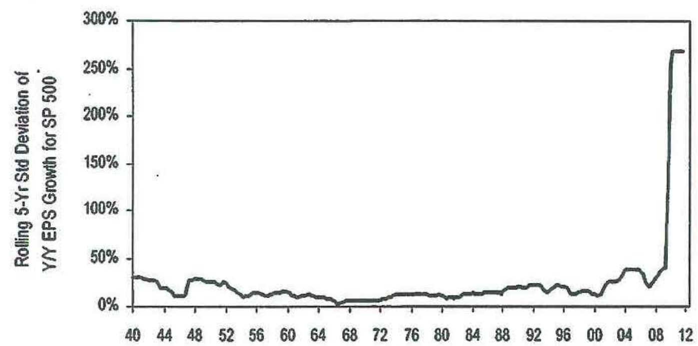
- We base our target on an equity risk premium of 650bp, which is roughly the average risk premium since the advent of the 2008 credit crisis (Chart 33).
- Our Dividend Discount Model derived equity risk premium is currently over 800bp, the highest in the history of our data and nearly double the 30-year average of 418bp.
- We see reasons for a structurally higher risk premium over the next several years given increased macro risk. Swings from losses to profitability over the last cycle have been (literally) off the charts (Chart 34), and the volatility of full cycle earnings growth is now at a 70-year high (Chart 35). In our view equities should incorporate a higher equity risk premium to compensate for this unprecedented level of earnings risk.

Chart 34: Profits cycle had such big swings in the last cycle...
Y/Y EPS Growth for S&P 500, 1935 to 2011



Source: BofA ML US Equity & Quant Strategy

Chart 35: ...that earnings volatility is now at 70-year high
Rolling 5-Yr Std Deviation of SP500 12-Mth Rep EPS Gth (2Q40-4Q11)



Source: BofA ML US Equity & Quant Strategy

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 283

Marginal Cost of Service

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Bonnie Gariety
Bruce Werner

February 13, 2014

Table of Contents

I. Introduction and Summary

Q. Please state your names and positions.

A. My name is Bruce Werner. I am responsible for the Distribution Marginal Cost Study in Section II.

My name is Bonnie Gariety and I am responsible for the Customer Service 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 IV.

Q. What is the purpose of your testimony?

A. Our testimony describes the distribution and customer service marginal cost studies. PGE Exhibit 1301 provides a summary of these marginal costs by component. The summary lists costs by PGE rate schedule for subtransmission, substation, feeder backbone and tapline, transformers, service laterals, meters and customer service costs. Generation Marginal Cost and rate schedule changes are discussed in PGE Exhibit 1400.

Q. What is the purpose of the distribution and customer marginal cost studies?

A. The purpose is to calculate the incremental, or marginal, cost of service to each customer class. The starting point for calculating marginal costs is the identification of the fundamental cost drivers for the distribution facilities and customer services that cause PGE to incur costs. Marginal costs are used to calculate marginal cost revenues; that is, the revenues PGE would collect if all of its customers were charged rates that equal marginal costs. In practice, rates can deviate from marginal costs in order to establish charges that recover the authorized revenue requirement.

Q. Are marginal costs an important tool for setting prices?

A. Yes. One of the primary goals of marginal cost theory is to encourage the efficient use of goods and services by pricing them at marginal cost. When utility rates are not set equal to marginal costs, users of these services may over consume or avoid otherwise economic consumption. Currently, there is growing interest in customer owned distributed generation and other demand response initiatives. In this environment, inefficient pricing can lead to cross-subsidies or uneconomic bypass of utility facilities. Electric prices based on marginal costs are` an important tool for utilities and their customers to make financial decisions that reflect the most economic use of the services provided by PGE.

Q. How are the results of the marginal cost studies used?

A. PGE Exhibit 1300 uses the results of this study to spread PGE's proposed revenue requirement across the relevant customer classes.

II. Distribution Marginal Cost Study

Q. Which marginal distribution costs do you calculate?

A. We calculate marginal distribution costs (separately) for subtransmission, substations, distribution feeders (backbone facilities and local facilities), line transformers (including services), 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 2014-2018. We then annualize these capital expenditures and divide by the growth in system non-coincident peak. Customers served at subtransmission voltage are excluded from this calculation because they supply their own substation. Table 1 in our work papers supports the PGE Exhibit 1301 - summary of marginal subtransmission and substation costs.

Q. How do you calculate the marginal unit 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 schedules' proportionate contribution to non-coincident peak (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 schedules 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. 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 the costs.

Table 2 in our work papers supports the PGE Exhibit 1301 - summary of marginal distribution feeder costs in.

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 used the current cost of underground facilities exclusively in our marginal feeder tapline cost calculations.

Q. How do you calculate marginal transformer and service costs?

A. We calculate each schedule's marginal transformer and service 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. Table 3 in our work papers supports PGE Exhibit 1301 - summary of marginal transformer and service costs.

Q. Please describe how you calculate the marginal costs of meters.

A. We calculate marginal meter costs as the installed cost of an Advanced Metering Infrastructure (AMI) meter for each customer and then apply an annual carrying charge. Table 4 in our work papers supports the PGE Exhibit 1301 - summary of meter marginal cost.

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 added to the per unit marginal capital cost. Table 5 in the work papers provides the details of this allocation and the final summary of distribution marginal costs by functional category in PGE Exhibit 1301.

Q. Does this conclude your description of distribution marginal costs?

A. Yes.

III. Customer Service Marginal Cost Study

Q. How are the customer service marginal costs used in the rate design process?

A. Marginal cost are considered when designing rates (for each rate group) to recover the allocated revenue requirements. PGE uses marginal/cost the study to guide the allocation of the customer service functional revenue requirements in the ratespread process.

Q. What are the fundamental cost drivers for customer service marginal cost?

A. The number of customers is a cost driver since each customer requires an interconnection with the PGE system. Also, PGE incurs cost in managing its relationship with customers, including handling customer communications, measuring usage, maintaining records, and billing.

Q. Briefly describe how you calculate the marginal cost.

A. The forecasted 2015 cost for each rate schedule is divided by the 2015 forecasted customer counts to derive the marginal cost per customer for each rate schedule.

Q. Do you calculate the marginal costs for metering, billing and other services?

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. PGE Exhibit 1301 provides details on these costs.

Q. Does PGE use a forecasted test year in the customer marginal cost study?

A. Yes. PGE uses forecasted costs for the 2015 test period and 2012 actual costs to develop the 2015 test year customer marginal costs (CMC). The 2015 forecasted costs are also referred to as budget amounts in this testimony.

Q. Is the study's methodology the same as in PGE's last rate case – UE 262?

A. Yes. The methodology is the same. There are some variations in the calculations that are discussed in this testimony. As in UE 262, the costs are allocated by PGE accounts directly on the basis of cost causation and a few are allocated based on sub-allocation of the other account costs. After the costs are spread across rate schedules, the final result is marginal costs for each rate schedule by the three functionalized categories: billing, metering, and other services.

A. PGE Accounts

Q. What PGE Accounts are used in the study?

A. The 2012 actual and 2015 forecasted costs for the study are collected for PGE accounts 9020001, 9030001, 9050001, 9080001, and 9090001. This set of data is the basis for determining marginal cost by PGE Rate Schedule.

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 PGE Exhibit 1302. Account numbers 9020001, 9030001 and 9050001 are customer account expenses and account numbers 9080001 and 9090001 are customer service and informational expenses.

B. Functionalization of Cost

Q. Are the costs further categorized before determining the final marginal costs?

A. Yes. The costs are functionalized into metering, billing and other services categories. The purpose of functionalization is to improve the accuracy of the cost allocation process.

Then, the costs are further segmented by PGE department. A department is also referred to as a Responsibility Center (RC). In the work papers the departments are identified by RC number and department title. This is the same approach as in our previous general rate case.

Q. Briefly describe which accounts and departments contribute to the metering?

A. Metering costs consist of PGE account 9020001. The metering 2015 budget amounts are allocated by rate schedule based on various cost-causation principles.

Q. Can you provide an example?

A. Yes. The 2015 forecasted budget amount for PGE account 9020001, Field Collection Department (RC 452), is allocated based on a weighted percentage of customers (less unmetered lighting and signals) and manual meter reads. In terms of manual meter reads, PGE projects in 2015 that the AMI network upgrades will be completed; therefore, fewer marginal costs are attributed to metering than in the previous rate case.

Q. Briefly describe which accounts and departments contribute to billing.

A. Billing costs consist of PGE account 9030001. The billing 2015 budget amounts of the departments are allocated by rate schedule based on cost causation. Some of the costs are allocated directly on the basis of cost-causation and some of the other accounts are allocated on a sub-allocation of the other accounts within billing.

Q. Can you provide examples?

A. Yes.

- The department costs for Retail Receivables and Field Collections are allocated based on percentage of adjusted write-offs by rate schedule.

- The department costs for Specialized Billing are allocated by the number of customers on direct access.
- The department costs for the Business Services Group are allocated by number of customers.
- Customer Information System billing costs are allocated by the number of customers, except streetlights and signals.

Q. Briefly describe which accounts and departments contribute to other services?

A. Other services costs mainly consist of PGE accounts 9050001 and 9080001. The marginal costs are calculated in the same manner as billing and are based on cost-causation principles.

Q. Can you provide examples?

A. Yes.

- The budget amount associated with the Customer Contact Operations is allocated by the number of customers on rate schedules using up to 200 kW.
- The budget amount for the Direct Access Operations Department is allocated by the number of customers participating in the direct access program.
- The budget amount for the Special Attention and Customer Channels Departments are allocated based on the customer counts.
- The Solar Payment Option and Net Metering Operations budget amounts are allocated by the number of customers participating in the programs.
- The Distributed Resources Department is allocated by customer accounts because all customers accrue benefits of this program.

- The Business Model budget amount is allocated by a percentage split between residential and nonresidential customers. The percentage split is based on how much of the budget is attributed to serving residential or non-residential customer groups.

Q. Were any adjustments made to these categories?

A. Yes. One adjustment was made. As in UE 262, the Business Customer Department, PGE account 9030001 is removed from the billing category and placed in the other services category since this department provides customer service and manages relationships with PGE's largest customers.

Q. How are the marginal costs by functionalized category determined?

A. After the forecasted 2015 budget amounts for each department are allocated across the PGE rate schedules, the dollar amounts are summed by rate schedule and divided by the number of customers. This result is a marginal cost for each rate schedule by the functionalized category.

C. Allocation of Cost

Q. What is the purpose of the allocation of costs?

A. The purpose is to assign costs among more than one customer class. Allocation occurs by developing mathematical factors that distribute costs to the customer classes according to how they cause PGE to incur costs.

Q. What are the typical factors used to allocate costs?

A. For the most part, the number of customers being served under each rate schedule is used to allocate costs. In the billing category, some support costs are based on sub-allocations within the functional category. In one instance, a weighted average of number of customers and energy is used. Finally, the dollar amount of unpaid bills over a three-year period, which is referred to as write-offs, is used to determine a percentage of write-offs by rate schedule.

Q. Have any of the allocations changed since the last rate case in UE 262?

A. Yes. The Business Customer Group is the PGE department (RC 527) that serves PGE's largest industrial and business customers. In recent rate cases, the allocation was based on a 20/80 percent weighted average between the number of accounts and total energy amounts by rate schedules.

The costs for this department are allocated to all schedules (except residential), including small non-residential customers (Schedule 32). Some very large customers have hundreds of accounts ranging from Schedules 32 to 89 and a Business Customer Representative serves that large customer and all the associated accounts. Typically, one stand alone small non-residential customer (Schedule 32) customer would not be served by this department.

Q. How was the allocation modified?

A. To ensure that the appropriate amount of costs are allocated to Schedule 32 and the other larger schedules, the allocation is now based on a weighting between number of high-level customer names (5%) and energy (95%). By using the high-level customer name rather than the number of accounts results in a reasonable allocation of costs based on the way the PGE representatives serve customer accounts.

Using this revised percentage split results in similar percentages as in the last general rate case for most Schedules, particularly the lighting Schedules (Schedule 91, 92, and 95). However, the percentage for Schedule 32 significantly decreases.

Q. How are the marginal costs determined for the large account schedules?

A. A new Schedule 90 for very large non-residential accounts became effective in January 2014. The Schedule 90 customer was previously on Schedule 89. The service characteristics are very similar for Schedule 90 and Schedule 89. Given these similar characteristics it's reasonable to expect similar marginal costs results.

However, because Schedule 90 has a very small number of accounts, the Other Services marginal cost for Schedule 90 is considerably higher in comparison to Schedule 89 and the Billing marginal cost is very low. To align the marginal costs with the service characteristics of the two schedules, the allocated costs and customer counts are combined; thereby, producing the same marginal cost for Schedule 89 (over 4 KW) and Schedule 90.

Q. How is the percentage of write-offs by rate schedule calculated?

A. As in previous rate cases, the dollar amount of write-offs over a three year period is totaled by rate schedule. Then the three-year dollar amount per rate schedule is divided by the total write-off amount to arrive at the percent of write-offs by rate schedule.

Q. What is the purpose of the write-off percentages?

A. These percentages are used to allocate the O&M budget amounts for the Field Collections and Retail Receivables Departments.

Q. Do you continue with the adjusted write-off method?

A. Yes. In UE 262 an adjusted write-off amount was used which excluded Schedules 85 and 89[1] because the Key Customer Group manages large customer accounts and any bill collections or write-offs that occur. The adjustment is made to ensure costs are only

[1] The adjusted write-off approach was first employed in UE 262. Staff's position was this method is appropriate. The O&M budget costs for Field Collection and Retails Receivables is not spread to large customer groups.

spread to customer groups managed by the Field Collections and Retail Receivables Departments.

Q. How is the percentage of meter reads by rate schedule calculated?

A. By 2015 some manual meter reads may still occur, but the number of manual reads will be minimal as PGE fully transitions to AMI. The decline in metering expenses in 2015 reflects this transition. The number of manual meter reads from 2012 is used to allocate the remaining metering costs. 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. Then a percentage by rate schedule is determined. The percentage of meter 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. A weighting methodology is applied to the billing and other services categories. The weights are based on 2012 costs per customer. The 2012 weight is then multiplied by the forecasted 2015 number of customers, resulting in an adjusted 2015 customer count. Then the adjusted 2015 customer count is divided by the total number of customers to arrive at a percentage. Finally, that percentage is multiplied by the 2015 costs. This is the same approach employed in the previous rate case.

D. UE 262 Stipulated Agreement

Q. In UE 262 Parties agreed to adjust the total dollar amount for the Customer Engagement Transformation Initiative to $1.6 million for five years. Was this adjustment applied in the 2015 test year?

A. No. The $1.6 million adjustment was removed entirely. All costs associated with the Customer Engagement Transformation (CET) initiative are not included in the CMC study. The initiative is a multi-year development program and it is expected to be completely operational in 2017 or 2018. Therefore, the development operations and maintenance costs are fixed and are removed.

Q. If a decision were to be made to include the CET costs in the CMC, how should the allocation be made?

A. In UE 262 the general suballocation approach was applied to the CET costs. For the 2015 test year, PGE would spread the costs based on the number of customers participating on each rate schedule.

Q. Does this conclude your description of customer service marginal costs?

A. Yes.

V. Qualifications

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. 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, marginal/cost, and various regulatory issues. Previously, I was an analyst with the 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. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
1301	Marginal Cost Study
1302	Description of PGE Account Numbers

PORTLAND GENERAL ELECTRIC
SUMMARY OF MARGINAL COST STUDY

SCHEDULE	SUBTRANSMISSION COSTS	SUBSTATION COSTS	FEEDER BACKBONE COSTS	FEEDER TAPLINE COSTS	SERVICE & TRANSFORMER COSTS	METER COSTS	CUSTOMER COSTS
	($/kW)	($/kW)	($/kW)	($/kW)	($/Customer)	($/Customer)	($/Customer)
Schedule 7 Residential							
Single-phase	$7.31	$13.75	$23.78	$16.07	$70.70	$20.41	$33.98
Three-phase	$7.31	$13.75	$23.78	$16.07	$132.84	$55.98	$33.98
Schedule 15 Residential	$7.31	$13.75	$24.65	$16.75	$5.45	N/A	$30.19
Schedule 15 Commercial	$7.31	$13.75	$24.65	$16.75	$5.45	N/A	$27.69
Schedule 32 General Service							
Single-phase	$7.31	$13.75	$27.38	$23.44	$101.80	$17.21	$33.41
Three-phase	$7.31	$13.75	$27.38	$9.36	$220.15	$68.38	$33.41
Schedule 38 TOU							
Single-phase	$7.31	$13.75	$33.20	$19.24	$193.91	$51.03	$48.18
Three-phase	$7.31	$13.75	$33.20	$13.38	$526.06	$120.77	$48.18
Schedule 47 Irrigation							
Single-phase	$7.31	$13.75	$69.29	$49.24	$7.81	$55.55	$26.64
Three-phase	$7.31	$13.75	$69.29	$25.31	$17.45	$81.68	$26.64
Schedule 49 Irrigation							
Single-phase	$7.31	$13.75	$71.27	$32.54	$136.12	$57.97	$32.99
Three-phase	$7.31	$13.75	$71.27	$25.37	$143.01	$66.46	$32.99
Schedule 83 Secondary General Service							
Single-phase	$7.31	$13.75	$23.92	$19.79	$327.25	$49.85	$95.03
Three-phase	$7.31	$13.75	$23.92	$8.91	$922.30	$110.53	$95.03
Schedule 85 Secondary General Service	$7.31	$13.75	$20.68	$7.16	$1,498.94	$151.83	$596.74
Schedule 85 Primary General Service	$7.31	$13.75	$20.68	$7.16	$687.64	$1,389.55	$596.74
Schedule 85 Secondary 1-4 MW	$7.31	$13.75	$21.44	$4.92	$4,057.83	$164.86	$1,778.17
Schedule 85 Primary 1-4 MW	$7.31	$13.75	$21.44	$4.92	$812.48	$1,389.55	$1,778.17
			($/Customer)				
Schedule 89 Secondary GT 4 MW	$7.31	$13.75	$83,473	N/A	$13,786.94	$164.86	$17,096.92
			($/Customer)				
Schedule 89 Primary GT 4 MW	$7.31	$13.75	$83,473	N/A	$2,550.00	$1,389.55	$17,096.92
			($/Customer)				
Schedule 89 Subtransmission	N/A	N/A	$89,081	N/A	N/A	$16,656.05	$17,096.92
			($/Customer)				
Schedule 90 Primary	$7.31	$13.75	$264,139	NA	$2,550.00	$1,389.55	$17,096.92
Schedules 91 & 95 Streetlighting	$7.31	$13.75	$24.65	$16.75	$4.33	N/A	$279.53
Schedules 92 Traffic Signals	$7.31	$13.75	$24.65	$9.17	$8.16	N/A	$225.62

Customer Service Marginal Costs
Account Definitions

PGE Customer Accounts Expense

Account	Title	Description
9020001	CustAcct-Meter Reading Exp.	Labor and expenses associated with on-and off-cycle customer meter reading. Expenses include any equipment / clothing requirments, vehicle use and fleet/fuel allocation, office data input
9030001	CustAcct-CustRecords&Collect	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	CustAcct-MiscCustomerAcctsExp	Labor and expenses associated with answering residential and non-residential general account questions (eg, open/close orders, name changes, account balances, outages, etc.). Also includes labor and expenses associated with special needs customer assistance such as social agency referrals and interventions.

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.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 283

Pricing

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Marc Cody

February 13, 2014

Table of Contents

I. Introduction and Summary

Q. Please state your name and position.

A. My name is Marc Cody. I am a Senior Analyst in Pricing and Tariffs for PGE. My qualifications are described in Section IX.

Q. What is the purpose of your testimony?

A. My testimony and accompanying exhibits demonstrate how the proposed E-18 Tariff changes recover Portland General Electric's (PGE) 2015 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, my testimony also describes the marginal cost of generation, the revenue requirement allocation process (ratespread), and the rate design. I also discuss the impact of the Schedule 89 Basic Charge at the lower end of the 4 MW threshold, streetlight rate design, and changes to various supplemental schedules. Included in these supplemental schedules are Schedule 122 Renewable Resources Automatic Adjustment Clause, Schedule 125 Annual Power Cost Update, and Schedule 126 Annual Power Cost Variance Mechanism. Also included is Schedule 143, Spent Fuel Adjustment that provides refunds to customers related to the settlement of decommissioning expenses for the Trojan nuclear plant. Schedule 143 also contains tax credits from the Oregon Department of Energy for the Independent Spent Fuel Storage Installation at Trojan. Finally, I include an estimate of Schedule 102 Regional Power Act (RPA) Exchange Credit price changes related to the 2008 Interim Agreement True-up Payment which results from the settlement of litigation.

Q. Please summarize the projected Cost of Service rate impacts resulting from the proposed allocations.

A. Table 1 below summarizes the rate impacts for the major rate schedules. These rate impacts include Schedules 102 and 143, and the impacts of the two new generation resources that PGE proposes to include in rates during 2015. The rate impacts from the two new generation resources and the proposed January 1, 2015 changes are provided separately within Table 1. PGE Exhibit 1402 contains more detailed information on the rate impacts for the individual schedules. Tables 1 through 4 of Exhibit PGE 1402 contain the impacts of the proposed prices effective January 1, 2015. Tables 5 and 6 build from Table 4 and reflect both the proposed January 1 price changes and the incremental impacts of Port Westward 2 (PW2) and Tucannon River Wind Farm (Tucannon) respectively. The detailed bill impacts contained in PGE Exhibit 1402 relate to prices effective January 1, 2015. I include in the work papers detailed bill impacts with the proposed prices for PW2 and Tucannon.

Table 1
Estimated Cost of Service Rate Impacts

Schedule	Jan. 1, 2015	PW2	Tucannon	Total
Schedule 7 Residential	-0.1%	2.7%	2.4%	5.0%
Schedule 32 Small Nonresidential	-0.6%	2.6%	2.4%	4.4%
Schedule 83 31-200 kW	-1.4%	3.1%	2.9%	4.6%
Schedule 85 201-4,000 kW	-1.8%	3.5%	3.2%	4.9%
Schedule 89 Over 4,000 kW	-1.7%	4.0%	3.6%	5.9%
Schedule 90 100 MWa	-3.2%	4.1%	3.8%	4.7%
COS Overall	-0.7%	3.0%	2.6%	4.9%
COS & DA Overall	-0.9%	2.9%	2.6%	4.6%

II. Marginal Cost of Generation

Q. What generation marginal cost methodology do you propose in this docket?

A. I propose a long-run methodology that explicitly takes into account the cost of marginal generation capacity and long-run marginal energy costs. This marginal cost methodology is similar to the manner of marginal cost estimation used to establish UE 262 prices.

Q. Please elaborate.

A. This methodology, frequently referred to as a "proxy peaker" methodology, uses a combined cycle combustion turbine (CCCT) for the long-run marginal generation resource. The fixed costs of a simple cycle combustion turbine (SCCT) are used to estimate the long-run capacity costs of the CCCT. All costs of the CCCT not assigned to capacity are assigned to energy. This is similar to how PGE calculates its Avoided Costs.

Q. What type of SCCT did you use to estimate the marginal capacity costs?

A. Consistent with the methodology used to establish UE 262 prices, I used an "F-class" SCCT. This unit has lower capital costs than the LMS 100 and reciprocating engine units PGE presents in its recent Integrated Resource Plans (IRPs).

Q. From where did you obtain the cost estimates for both the SCCT and the CCCT?

A. I obtained the location specific cost estimates for the SCCT from a publication titled "Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants." This publication is sponsored by the United States Department of Energy. I include a copy of this publication in the Pricing Work Papers. For the CCCT, I used the values contained in PGE's draft IRP, specifically the draft values contained in the May 28, 2013 presentation to stakeholders.

Q. Would you please provide a step-by-step description of how you estimated the marginal capacity and energy costs?

A. Below is a description of the process:

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 the 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 prior PGE IRPs.
3. Finally, express the annual capacity and energy values in real levelized terms.

Q. How do you calculate the 2015 test-period marginal capacity costs?

A. I multiply the real levelized annual capacity cost described above by the projected 2015 cost-of-service (COS) test-period peak-hour load. This peak-hour load is projected to occur in December.

Q. How do you allocate the marginal capacity costs to each rate schedule?

A. I allocate the 2015 test-period marginal capacity costs described above on the basis of each schedule's relative projected contribution to the monthly peak hours contained in the months of January, July, August, and December (4-concident peak or 4-CP).

Q. Why do you choose the four months of January, July, August, and December for the allocation of marginal capacity costs?

A. I choose these four months because they are the months with the highest peaks consistent with the periods identified as capacity deficient in prior IRPs. I also choose these months because PGE's highest annual peak-hours generally occur during one of these four months. Furthermore, these four months are consistent with the months used to establish UE 262 prices.

Q. How do you estimate each rate schedule's long-run marginal cost of energy?

A. I perform the following steps to calculate the 2015 hourly load profile and marginal cost of energy for each rate schedule:

1. For each schedule and each month, calculate a typical weekday, Saturday, and Sunday load shape using 2012 hourly load profiles.
2. Use these day-type hourly profiles to shape each schedule's monthly weather-normalized 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 below.

Q. How do you shape the annual long-run marginal cost of energy into hourly values?

A. I shape the annual long-run marginal energy cost into hourly values based on the energy price shaping used in PGE's production cost model, Monet.

Q. Do you include the projected costs of carbon dioxide compliance in your analysis?

A. Yes. I include compliance costs consistent with the environmental assumptions in the draft 2014 IRP. These compliance costs commence in 2023.

Q. Do you include a summary exhibit of the marginal capacity and energy costs?

A. Yes. PGE Exhibit 1403 contains the summary information.

III. Ratespread

Q. Please summarize the changes in ratespread, and rate design you have made since UE 262.

A. The key changes I propose are listed below (and explained later in testimony):

- Separately provide cost-of-service estimates and pricing for Schedule 90, a schedule for customers whose aggregated load exceeds 100 average megawatts (MWa).
- Re-open Schedule 38, Optional Time-of-Day Large Nonresidential Service to new customers whose demand exceeds 200 kW. This action should benefit some large seasonal and/or low load factor customers.
- Because the test period load forecast contains projections of Schedule 76R Partial Requirements Economic Replacement Power, I estimate the daily transmission and distribution demand revenues from this projected energy, and provide these revenues as an offset to the appropriate functionalized revenue requirements. In addition, I propose to eliminate the System Usage Charge for both Schedules 76R, and 576R, the direct access equivalent schedule of 76R. I discuss this change in the System Usage Charge later in testimony.

Q. Do you propose changes to existing supplemental schedules?

A. Yes. I propose some language changes to Schedules 122, 125, and 126 consistent with the testimony presented in PGE Exhibit 500. In addition, I propose that Schedule 143 Spent Fuel Adjustment be approved with an effective date of January 1, 2015. I also provide an estimate of the price change for Schedule 102 related to the 2008 Interim Agreement True-up payment from the Bonneville Power Administration.

Q. What is the basis for the functional allocation of costs to the rate schedules?

A. I use the 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 distribution and customer service portion of the Marginal Cost Study is presented in PGE Exhibit 1300.

Q. What are the respective capacity and energy percentages used in allocating the generation revenue requirements?

A. Capacity comprises approximately 25.4% of the marginal cost of generation, and energy 74.6%. The corresponding figures from UE 262 were approximately 25.8% and 74.2%.

Q. How do you allocate the costs of the two new generation plants?

A. I allocate the costs of PW2 and Tucannon to the COS rate schedules on the basis of the projected test period COS energy revenues (inclusive of the Schedule 90 load following/integration credit discussed later) before including the two new generating plants. These COS energy revenues are based on the generation marginal cost estimation described earlier, hence a consistent allocation of generation costs is achieved. A summary of the cost allocations of PW2 and Tucannon is presented in PGE Exhibit 1406.

Q. How will the price changes for PW2 and Tucannon be implemented?

A. After the Commission rules on the test-period revenue requirements for the two plants, PGE will implement changes in the COS Energy Charges and the Schedule 128 and 129 Transition Adjustments as appropriate through an Advice Filing. PGE will also file for the appropriate changes in Schedule 123 Decoupling Adjustment to reflect the increases in fixed costs.

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, I allocate it in the same manner as I do generation. I also allocate the transmission revenue requirement consistent with how UE 262 prices were established, 65% based on capacity, and 35% based on energy. These two functional categories combined with the five categories above complete the seven functional categories specified in ORS 757.642.

Q. Do you allocate other cost categories to the individual rate schedules?

A. Yes. I allocate franchise fees to the schedules on the basis of the test period revenue requirement allocations and Trojan decommissioning on a generation revenues basis. I allocate Schedule 129 Long-Term Transition Adjustment for enrollment periods A through K to Schedule 85, 89, and 90 customers on an energy basis, with subsequent enrollment periods allocated on an energy basis to all schedules. Finally, I allocate uncollectible expense based on historical incidence for the years 2010-2012. All allocations are presented in PGE Exhibit 1405.

Q. Please describe how you allocate and price the recovery of the franchise fee revenue requirements consistent with OPUC Order 12-500.

A. I allocate the franchise fee revenue requirements in the same manner as in UE 262. Therefore, I do not attribute cost responsibility for the generation and transmission functional categories to direct access customers. More specifically, I allocate 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 calculate the prices for each category of allocations. Because direct access customers do not pay generation and transmission charges to PGE, I calculate a franchise fee price differential related to these charges and apply this differential to the direct access schedules. This differential is inclusive of Schedule 129 revenues and is captured in the system usage charges for each direct access schedule. For direct access schedules that do not have a system usage charge, I 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, after spreading the revenue requirements, I apply the Customer Impact Offset (CIO) in order to temper the rate impacts to certain schedules. Specifically, I limit the rate increase for Schedules 47 and 49 to 12% before consideration of the two new generation resources.

IV. Rate Schedule Design

Q. Please provide a brief summary of the major COS Rate Schedules.

A. There are six major (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 (30 kW or less), 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 kW 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 on-peak periods within 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). The Energy Charge is mandatory Time-of-Use (TOU).

Schedule 85, Large Nonresidential Standard Service (201 kW to 4,000 kW), applies to customers from 201 kW to 4,000 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. The proposed Energy Charges continue to be on- and off-peak differentiated.

Schedule 89, Large Nonresidential Standard Service (>4,000 kW), applies to customers whose Facility Capacity exceeds 4,000 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.

Schedule 90, Large Nonresidential (>4,000 kW, aggregating to exceed 100 MWa) applies to customers whose Facility Capacity exceeds 4,000 kW and whose energy consumption exceeds 100 MWa. The rate design is similar to Schedule 89, but with much higher customer charges.

Q. What principles do you consider in developing the proposed prices?

A. I consider 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 do you develop the prices for each rate schedule?

[1] "Principles of Public Utility Rates," by James C. Bonbright, Albert L. Danielsen, and David R. Kamerschen, 2nd Edition, 1988.

A. I explain the development of prices for each of the major rate schedules below. PGE Exhibit 1404, 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	$11.00 per customer per month
Transmission & Related Service Charge	2.54 mills per kWh
Distribution Charge	40.25 mills per kWh
Energy Charge First 1,000 kWh	61.27 mills per kWh
Energy Charge Over 1,000 kWh	68.49 mills per kWh

Q. Please explain how you develop these prices.

A. Although the Marginal Cost Study results suggest a **Basic Charge** of approximately $21, I propose to increase it by one dollar, to $11.00 in order to better match prices to costs, consistent with the principles discussed above. I develop the **Transmission & Related Service Charge** directly from the allocated transmission and ancillary services revenue requirement.

I calculate the **Distribution Charge** of 40.25 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.

I 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. Do you incorporate a projection of the revenue impacts of the voluntary portfolio TOU option in the calculation of the energy price?

A. Yes. I 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 $134,000. I incorporate this impact in 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	Prices
Basic Charge Single Phase	$15.00 per customer per month
Basic Charge Three Phase	$20.00 per customer per month
Transmission & Related Services Charge	2.22 mills per kWh
Distribution Charge First 5,000 kWh	39.83 mills per kWh
Distribution Charge Over 5,000 kWh	10.27 mills per kWh
Energy Charge	58.25 mills per kWh

Q. Please describe how you develop the Schedule 32 prices.

A. Schedules 32 and 532 apply to Small Nonresidential customers, with Facility Capacity less than or equal to 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, I increase the Basic Charge for single- and three-phase service to $15.00 and $20.00 per month from their current levels of $14.00 and $18.00 respectively. These basic charges are still considerably below the marginal customer-related costs of approximately $24 and $44. As with Schedule 7, I capture the difference between the allocated costs and the various revenues within the Distribution Charge.

I compute the **Transmission and Related Services Charge** directly from the allocated transmission and ancillary service costs.

I retain the current Schedule 32, **Distribution Charge** blocking, with the initial block including usage up to 5,000 kWh. I set the second block for usage greater than 5,000 kWh on a declining basis to 7 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. I set this tailblock rate at a higher level than current 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, I include within the Distribution Charge the costs associated with franchise fees and Trojan Decommissioning.

I set the **Energy Charge** on a flat year-round basis that is based on the allocation of generation costs.

Q. Do you incorporate a projection of the revenue impacts of the voluntary portfolio TOU option in the calculation of the energy price?

A. Yes. I 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 $48,000. I incorporate this impact in 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. I 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. I 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 Prices	
Basic Charge Single Phase	$30.00	per customer per month
Basic Charge Three Phase	$40.00	per customer per month
Trans. & Related Services	$0.84	per on-peak kW
Distribution Demand Charge	$2.24	per on-peak kW
Facility Capacity Charge (First 30 kW)	$2.96	per kW Facility Capacity
Facility Capacity Charge (Over 30 kW)	$2.86	per kW Facility Capacity
System Usage Charge	6.72	mills per kWh
COS Energy Charge On-peak	61.59	mills per kWh
COS Energy Charge Off-peak	51.59	mills per kWh

Q. Please describe how you develop the Schedule 83 prices.

A. I propose to maintain the current Schedule 83 single-phase **Basic Charge** of $30.00 and the three-phase charge of $40.00. This pricing level 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, I set the **Transmission & Related Service Charge** to $0.84 per kW of on-peak demand consistent with the other secondary voltage customers served on Schedules 85 or 89. I do this to make the pricing more consistent for customers who choose Direct Access Service under Schedules 583, 585, 589, or 590. This charge results in more than a full recovery of Schedule 83 allocated costs, consequently I 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**. I recover the costs associated with the 13 kV system through the Facility Capacity Charge. I 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.

I set the **Demand Charge** which recovers distribution substations and 115 kV costs where applicable, at $2.24 per kW of on-peak demand by combining the demand-related costs and billing determinants for Schedules 83, 85, 89, and 90 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, I 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.

I calculate the COS Energy Charges based on the results of the generation allocations. I maintain the on-and off-peak differential at the current 10 mills per kWh.

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 Intercontinental Exchange Daily On- and Off-Peak Firm Pricing Index (ICE Mid-C Firm Index). Customers may also choose to receive service from an ESS.

Customers receiving service from an ESS or from a PGE market option receive the Schedule 128, Short-Term Transition Adjustment.

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. Please provide the proposed monthly prices for Schedule 85 and describe the customers to whom these prices apply.

A. Schedule 85 applies 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 I discuss below. I 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 Prices**		**Primary Prices**	
Basic Charge	$470.00	per customer per month	$500.00	per customer per month
Trans. & Related Services	$0.84	per on-peak kW	$0.82	per on-peak kW
Distribution Demand Charge	$2.24	per on-peak kW	$2.20	per on-peak kW
Facility Capacity Charge (First 200 kW)	$3.09	per kW Facility Capacity	$3.04	per kW Facility Capacity
Facility Capacity Charge (Over 200 kW)	$2.19	per kW Facility Capacity	$2.14	per kW Facility Capacity
System Usage Charge	1.14	mills per kWh	1.10	mills per kWh
COS Energy Charge On-peak	59.85	mills per kWh	58.81	mills per kWh
COS Energy Charge Off-peak	49.85	mills per kWh	48.81	mills per kWh

Q. Please describe how you develop the Schedule 85 prices.

A. The Schedule 85 **Basic Charges** differ by delivery voltage. For secondary service and primary voltage, I set the Basic Charges at $470.00 and $500.00 per month, respectively. The secondary voltage customer charge, subject to rounding, recovers the full amount of the allocated marginal customer-related costs. I set the primary voltage customer charge $30 per month higher, consistent with the current price differential. These customer charges combined with the declining block facilities charges help transition those Schedule 83 customers whose demand grows to exceed 200 kW. This declining block 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, 89 and 90, I set the **Transmission & Related Service Charge** to $0.84 per kW of on-peak demand for secondary service, and to $0.82 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, I 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 $2.24 and $2.20 for secondary and primary customers, respectively are set in conjunction with the demand charges for schedules 83, 89, and 90 as discussed earlier. I 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, I separately state the **System Usage Charge** which recovers franchise fees, Trojan Decommissioning costs, and the CIO. I also use this charge for Schedules 83, 85, 89, and 90 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.

I calculate the COS energy charges based on the results of the generation allocations. I maintain the on- and off-peak differential at 10 mills/kWh. I 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 Prices	Primary Prices	Subtransmission Prices
Basic Charge	$5,440.00 per month	$4,870.00 per month	$5,600.00 per month
Transmission & Related Charge	$ 0.84 per on-peak kW	$0.82 per on-peak kW	$0.81 per on-peak kW
Facility Capacity Charge First 4,000 kW	$1.97 per kW Facility Capacity	$1.94 per kW Facility Capacity	$1.94 per kW Facility Capacity
Facility Capacity Charge Over 4,000 kW	$1.50 per kW Facility Capacity	$1.47 per kW Facility Capacity	$1.47 per kW Facility Capacity
Distribution Demand Charge	$2.24 per on-peak kW	$2.20 per on-peak kW	$0.83 per on-peak kW
System Usage Charge	0.85 mills per kWh	0.82 mills per kW	0.80 mills per kW
COS Energy Charge On-peak	57.25 mills per kWh	56.29 mills per kWh	55.57 mills per kWh
COS Energy Charge Off-peak	47.25 mills per kWh	46.29 mills per kWh	45.57 mills per kWh

Q. Please describe how you develop the Schedule 89 Charges.

A. I 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, 85, and 90 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, 85, and 90. 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 six 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, I 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, I 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. I maintain the current differential of 10 mills/kWh, the same differential as for Schedules 83 and 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 provide the proposed monthly prices for Schedule 90 and describe the customers to whom these prices are applicable.

A. Schedule 90 applies to Large Nonresidential customers whose Facility Capacity exceeds 4,000 kW and whose aggregated load exceeds 100 average megawatts (MWa). All four of the accounts on Schedule 90 are served at primary delivery voltage; the prices are listed below:

Table 7
Schedule 90 General Service Greater than 4,000 kW aggregating to 100 MWa

Category	**Primary Voltage Prices**
Basic Charge	$25,000.00 per month
Transmission & Related Charge	$0.82 per on-peak kW
Facility Capacity Charge First 4,000 kW	$1.08 per kW Facility Capacity
Facility Capacity Charge Over 4,000 kW	$1.08 per kW Facility Capacity
Distribution Demand Charge	$2.20 per on-peak kW
System Usage Charge	0.71 mills per kW
COS Energy Charge On-peak	54.88 mills per kWh
COS Energy Charge Off-peak	44.88 mills per kWh

Q. Please describe how you develop the Schedule 90 Charges.

A. I set the **Basic Charge** at a level exceeding the normal customer cost categories because of the large size of the accounts on this schedule and because it is reasonable to think of the distribution feeders for very large customers as a customer-related cost.

Similar to Schedule 89, I calculate the **Transmission and Related Service Charge** in conjunction with Schedules 83, 85, and 89. Also, similar to Schedule 89, because this charge is less than the allocated costs, I use the Facility Capacity Charge to recover the remainder.

The **Distribution Demand Charge** is also calculated in conjunction with Schedules 83, 85, and 89. Any under-collection of costs is recovered through the Facility Capacity Charge.

I set the **Facility Capacity Charge** on a flat basis and flow through any over- or under-recovery of allocated costs through this charge.

The **COS Energy Charge** is differentiated by on- and off-peak hours with a 10 mills/kWh differential. There is also a Daily Price Option and Direct Access option similar to those for Schedules 85 and 89.

Q. Do you propose to continue the load following/integration credit for Schedule 90 used in UE 262?

A. Yes, in concept. I propose to continue this concept, applicable to 140 MWa instead of the 100 MWa used in UE 262, and to incorporate the credit amount of approximately $1.4 million into the base energy charges for Schedule 90 customers. This $1.4 million is allocated to other COS customers and recovered through their respective energy charges.

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:

I 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. I propose the current monthly $25 Basic Charge for single- and three-phase service customers. I 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. I increase the monthly Basic Charge to $35 per month for the six summer months only, and I 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. I increase the Basic Charge to $45 per month, summer months only. Similar to Schedule 47, I 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. I 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. I 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 temporarily reopen Schedule 38 for customers greater than 200 kW?

A. I propose this because PGE has some large seasonal and/or low load factor customers that may benefit from volumetric rather than demand-based pricing for distribution and transmission charges. Because PGE considerably raised its Basic Charges for Schedules 85 and 89 in UE 262, the option to switch schedules should be provided to large customers should they find it beneficial.

Q. Please describe why you propose to eliminate the Schedule 76R/576R System Usage Charge.

A. I propose to eliminate this charge because projections of partial requirements energy can vary widely due to changes in wholesale market conditions. If wholesale market prices are high, a partial requirements customer is likely to rely more heavily on self-generation, and the converse applies when wholesale market prices are low. Hence, it is appropriate to exempt partial requirements customers from the majority of the cost allocation process, including the System Usage Charge.

Q. What costs or true-ups are contained in the System Usage Charge?

A. Previously, the Schedule 76R system Usage Charge was set at the same level as the System Usage Charge for Schedule 89. The Schedule 89 System Usage Charge consists of the costs of Trojan decommissioning, franchise fee allocations, the Schedule 129 true-up, and the CIO.

Q. Do you propose other changes to Schedules 76R/576R?

A. Yes. For the reasons specified above, I propose to remove these schedules from most supplemental schedules. Specifically, I propose to remove Schedules 76R/576R from Schedules 105, 109, 110, 123, and 144. Schedules 76R/576R will still be subject to the legally mandated supplemental schedules such as Schedule 108 Public Purpose Charge. The compliance filing to this proceeding will contain the approved changes in the supplemental schedules above.

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 I were to price these schedules at cost, they would experience extremely large rate increases. I therefore propose to limit Schedules 47 and 49 to no more than a 12% percent base rate increase before consideration of the two new generation resources discussed in PGE Exhibit 400. Over time, PGE hopes to gradually move these schedules closer to cost of service while gradually sending the appropriate price signal.

Q. Which schedules bear the costs of mitigation of the schedules mentioned above?

A. I 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. I exempt the lighting schedules because of the desire to maintain the same volumetric charges for Schedules 15, 91, and 95 discussed below.

Q. How do you implement the CIO mitigation?

A. I increase the System Usage Charges for Schedules 83, 85, 89, and 90, and I increase the distribution charges for the other impacted rate schedules to offset the effect of the price mitigation efforts described above. Schedules receiving the CIO subsidy do so through their distribution charges. I also use the CIO to equalize the distribution charges for the outdoor lighting schedules 15, 91, and 95. PGE Exhibit 1404 shows the development of this offset.

V. Streetlights

Q. Do you propose changes in the manner in which you price Area Lights and Streetlights?

A. I do not propose to change the pricing methodology of either Streetlights or Area Lights. The methodology that was used in UE 262 is used in this docket.

Q. Please describe how you calculate the amount of outdoor lighting maintenance.

A. Similar to UE 262, I 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, I express the historical maintenance amounts on a per-light basis, and then escalate this per-light maintenance figure for inflation. A further reduction is made for LED street and area lights since (1) their maintenance is significantly less than other lights, and (2) the years used in the most recent 5-year re-lamping cycle do not include LEDs. Following this, I 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 proposed for the 2015 test period – based on the historical re-lamping cycle – is approximately $95,000 lower than the amount calculated in the marginal cost study.

Q. Please explain the relatively large decrease of approximately 3,480 MWh in Schedule 15 projected energy relative to UE 262.

A. PGE is currently executing a planned conversion of 11,292 eligible area lights. Existing old-technology fixtures are being converted to Light Emitting Diode (LED) technology. The conversion of high pressure sodium (HPS), Mercury Vapor (MV) and Metal Halide (MH) lights to LED fixtures accounts for this estimated energy use decrease.

Q. Do you provide a summary exhibit of the proposed pole and luminaire prices?

A. Yes. This summary is provided in PGE Exhibit 1407.

VI. UE 262 Stipulation Follow-Up

Q. What is the purpose of this portion of your testimony?

A. The purpose of this portion of testimony is to discuss the follow-up efforts related to the UE 262 Schedule 89 Customer Charge Stipulation.

Q. With respect to this proceeding, what did the Stipulation specify?

A. The stipulation specified that PGE would study the impact of the Schedule 89 Basic Charge on low load factor customers at the lower end of the 4 MW threshold and communicate the results of such study in its next general rate case filing.

Q. Please specify the cost elements that comprise the Schedule 89 Basic Charge.

A. The Schedule 89 Basic Charge consists of the following cost elements: meters, service and transformers (secondary voltage only), uncollectable amount allocations, and the customer cost categories metering, billing, and other consumer.

Q. Do you consider these cost elements as being customer-related as opposed to demand- or energy-related?

A. Yes, I consider these costs to be customer-related.

Q. Do you propose to recover the full amount of these costs in the Schedule 89 Basic Charge?

A. No. In this docket, as in UE 262, I propose to recover 50% of these Schedule 89 customer costs through the Schedule 89 Basic Charge. As I stated earlier in testimony, costs not recovered through the basic charge are recovered through the Facility Capacity Charge.

Q. What would be the result if you lowered the Schedule 89 Basic Charge and recovered the additional unrecovered costs through the Facility Capacity Charge?

A. The result depends on whether the additional unrecovered costs would be recovered through the first block of the Facility Capacity Charge or if the additional unrecovered costs would be spread either over both blocks, or perhaps to just the tail-block rate. In the first instance, there would be little or no difference in the impacts for smaller, low load factor customers. In the second instance, the smaller, low load factor customers would benefit, but at the expense of larger Schedule 89 customers.

Q. Would you please provide an example of what would occur if you either lowered the Basic Charge or raised it and commensurately raised or lowered the tail-block Facility Capacity Charge?

A. I created two hypothetical Schedule 89 primary voltage customers with very different characteristics. Customer 1 has a peak demand of 4,100 kW monthly with a 20% load factor and Customer 2 has a 90% load factor with a peak demand three times larger. For the base case, I set the Basic Charge to recover 50% of customer costs and blocked the Facility Capacity Charges to enable a relatively smooth migration between Schedules 85 and 89. I then reset the Basic Charge to reflect two different levels of recovery of customer costs through the Basic Charge. In the first instance, I set the Basic Charge to recover 25% of customer costs and allowed the tail-block Facility Capacity Charge to recover the lower level of costs not recovered in the Basic Charge. In the second instance, I set the Basic Charge to recover 100% of the customer costs and allowed the tail-block Facility Capacity Charge to be set commensurately lower than the base case of 50% recovery of customer costs through the Basic Charge. A summary of the analysis using base rates before inclusion of the two new generation resources is below:

Table 8
Schedule 89 Primary Voltage with Different Basic Charges and Bill Impacts

Customer/Case	Basic Charge	Base Rate Bill	Pct. Change from Base Case
Low load factor 50%	$4,870.00	$56,951	
Low load factor 25%	$2,430.00	$54,511	-4.3%
Low load factor 100%	$9,730.00	$61,772	8.5%
High load factor 50%	$4,870.00	$491,164	
High load factor 25%	$2,430.00	$492,004	0.2%
High load factor 100%	$9,730.00	$489,507	-0.3%

Q. Does the summary above convince you that you should either lower or raise the Basic Charge from the 50% level of cost recovery that you propose?

A. No. While it could be argued that setting the Schedule 89 Basic Charge at 100% of allocated costs better reflects cost-causation for these large customers, the proposal to set the Basic Charge at 50% of allocated costs strikes a reasonable balance among the various Schedule 89 customers, the majority of whom have high load factors. The percentage impacts from reducing the customer charge appear to make a case for lowering the customer charge, but this is partially due to the fact that in this example, the large, higher load factor customer has a monthly bill that is more than eight times larger than the smaller, low load factor customer. The higher bill for the larger, high load factor customer is due primarily to the amount of the bill devoted to energy charges. The proposed Basic Charge may seem high to some, but it is important to remember that the proposed Schedule 89 prices do not contain a generation demand charge, which all else equal would make the bill impacts for low load factor customers more onerous.

VII. Other Rate Schedule Changes

Q. Please describe the changes you propose to make to Schedule 125.

A. For Schedule 125 Annual Power Cost Update, I propose to include reciprocating engine lubrication oil in the list of allowable annual updates.

Q. Please describe the changes you propose to make to Schedules 122 and 126.

A. For Schedule 126, I propose to include reciprocating engine lubrication oil within the definition of Net Variable Power Costs. I also propose language changes for both Schedules 122 and 126 that enable the proposed renewable resource changes discussed in PGE Exhibit 500.

Q. Please describe Schedule 143.

A. Schedule 143 Spent Fuel Adjustment consists of two parts. The first part consists of the amortization of the excess funds currently contained in the Trojan Nuclear Decommissioning Trust Fund. The second part consists of the amortization of payments from the Oregon Department of Energy related to state pollution tax credits for the Independent Spent Fuel Storage Installation (ISFSI) at Trojan.

Q. What are the estimated amounts you propose to amortize and over what time period do you propose to amortize these two regulatory liabilities?

A. The trust fund refund is approximately $50 million and the ISFSI tax credits are approximately $5.5 million. I propose a three-year amortization for the trust fund refund (Part A) and a one-year amortization for the ISFSI refund (Part B). The amounts stated above are estimates and are subject to change as more information becomes available.

Q. How do you propose to allocate the Schedule 143 amounts?

A. I propose to allocate the two parts on the basis of generation revenues with long-term direct access customers priced at cost-of-service energy prices. Hence, long-term direct access customers will receive the Schedule 143 credits in the same manner as COS customers. This is consistent with long-term direct access customers continuing to pay for the cost of decommissioning Trojan.

Q. What is the estimated amount of the 2015 proposed Schedule 143 amortization?

A. For 2015, it is a refund of approximately $22.7 million.

Q. Do you incorporate an estimate of the Schedule 102 price change related to the Interim Agreement True-up Payment from the Bonneville Power Administration (BPA)?

A. Yes. I provide a rough estimate of the Schedule 102 prices with the $12 million PGE expects to receive from BPA. I estimate the 2015 Schedule 102 prices by amortizing the $12 million plus estimated associated interest over two years and adding this amortization to current Schedule 102 prices. I expect to update the proposed 2015 Schedule 102 prices through an Advice Filing to occur in October or November of 2014.

VIII. Line Losses

Q. Have you performed an update to the current line loss study?

A. Yes. PGE Exhibit 1408 summarizes the results by delivery voltage. The overall estimate of percentage line losses has decreased. The detailed calculations and data used to develop the line loss percentages are contained in the Pricing work papers.

Q. How do you use the line loss percentages in Exhibit 1408?

A. The line loss percentages are an input to the busbar load forecast. In addition these percentages are used for marginal cost of generation estimates and in energy pricing for variable price option customers. The internal loss percentages are used by Energy Service Suppliers (ESSs) for scheduling energy to deliver to PGE's service territory. These losses are contained in Schedule 600.

IX. 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
1401	Proposed Tariff Changes
1402	Estimated Impact of Proposed Changes on Customers
1403	Marginal Generation Costs
1404	Rate Design
1405	Allocation of Costs to Customer Classes
1406	Allocation of Costs of Port Westward 2 and Tucannon Wind Farm
1407	Streetlight and Area Lights
1408	Line Losses

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	$11.00		(I)
Three Phase Service	$11.00		(I)
Transmission and Related Services Charge	0.254	¢ per kWh	(R)
Distribution Charge	4.025	¢ per kWh	(I)
Energy Charge Options			
Standard Service			
First 1,000 kWh	6.127	¢ per kWh	(R)
Over 1,000 kWh	6.849	¢ per kWh	
or			
Time-of-Use (TOU) Portfolio (Whole Premises or Electric Vehicle (EV) TOU) (Enrollment is necessary)			
On-Peak Period	11.933	¢ per kWh	
Mid-Peak Period	6.849	¢ per kWh	
Off-Peak Period	3.979	¢ per kWh	
First 1,000 kWh block adjustment**	(0.722)	¢ per kWh	(R)

* 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	0.176	¢ per kWh	**(R)**
Distribution Charge	4.781	¢ per kWh	**(I)**
Cost of Service Energy Charge	4.966	¢ 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	$12.57 (2)	**(R)**
	400	21,000	147	21.00 (2)	**(I)**
	1,000	55,000	374	44.18 (2)	**(I)**
HPS	70	6,300	30	9.11 (2)	**(R)**
	100	9,500	43	10.34	**(R)**
	150	16,000	62	12.25	**(R)**
	200	22,000	79	14.25	**(I)**
	250	29,000	102	16.50	**(R)**
	310	37,000	124	19.08(2)	**(R)**
	400	50,000	163	22.96	**(I)**
Flood, HPS	100	9,500	43	10.38(2)	**(R)**
	200	22,000	79	14.94(2)	
	250	29,000	102	17.24	
	400	50,000	163	23.29	
Shoebox, HPS (bronze color, flat lens or drop lens, multi-volt)	70	6,300	30	10.46	
	100	9,500	43	11.94	
	150	16,500	62	14.08	
Special Acorn Type, HPS	100	9,500	43	14.80	
HADCO Victorian, HPS	150	16,500	62	16.58	
	200	22,000	79	18.99	
	250	29,000	102	21.32	
Early American Post-Top, HPS Black	100	9,500	43	11.10	**(R)**

(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	$12.68	(R)
	175	12,000	71	14.01	
Flood, Metal Halide	350	30,000	139	22.23	
	400	40,000	156	22.80	
Flood, HPS	750	105,000	285	38.33	
HADCO Independence, HPS	100	9,500	43	14.80	
	150	16,000	62	16.39	
HADCO Capitol Acorn, HPS	100	9,500	43	18.52	
	150	16,000	62	20.34	
	200	22,000	79	22.01	
	250	29,000	102	24.31	
HADCO Techtra, HPS	100	9,500	43	23.47	
	150	16,000	62	24.86	
	250	29,000	102	28.22	
HADCO Westbrooke, HPS	70	6,300	30	16.25	
	100	9,500	43	17.31	
	150	16,000	62	19.20	
	200	22,000	79	21.15	
	250	29,000	102	23.28	
KIM Archetype, HPS	250	29,000	102	26.11	
	400	50,000	163	27.33	
Holophane Mongoose, HPS	150	16,000	62	17.03	
	250	29,000	102	20.35	(R)

(1) See Schedule 100 for applicable adjustments.

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)
Rates for LED Area Lighting

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate Per Luminaire[1]	
Acorn					
LED	60	5,488	21	$14.72	(R)
	70	4,332	24	16.86	
Cobrahead Equivalent					
LED	37	2,530	13	5.06	
	50	3,162	17	5.46	
	52	3,757	18	5.95	
	67	5,050	23	6.71	
	106	7,444	36	8.82	
Westbrooke LED (Non-Flare)	49	5,094	17	19.00	
	69	6,680	24	20.44	
	109	8,176	37	21.99	
	136	12,728	46	26.45	
	206	18,159	70	28.84	
Westbrooke LED (Flare)	49	5,094	17	21.07	
	69	6,680	24	22.10	
	109	8,176	37	24.04	
	136	12,728	46	27.73	
	206	18,159	70	30.12	(R)
CREE XSP LED	25	2,529	9	3.70	
	42	3,819	14	4.30	(I)
	48	4,373	16	4.97	(R)
	56	5,863	19	5.78	
	91	8,747	31	6.97	(R)

(1) See Schedule 100 for applicable adjustments.

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)

Type of Pole	Pole Length (feet)	Monthly Rate Per Pole	
Rates for Area Light Poles[1]			
Wood, Standard	35 or less	$7.03	(R)
	40 to 55	9.20	
Wood, Painted for Underground	35 or less	7.03 [2]	
Wood, Curved Laminated	30 or less	8.71 [2]	
Aluminum, Regular	16	8.39	
	25	13.93	
	30	15.05	
	35	18.00	
Aluminum, Fluted Ornamental	14	12.29	
Aluminum Davit	25	12.88	
	30	13.83	
	35	15.12	
	40	20.52	
Aluminum Double Davit	30	20.42	
Aluminum, HADCO, Fluted Ornamental	16	12.56	
Aluminum, HADCO, Non-fluted Techtra Ornamental	18	24.18	(R)
Aluminum, HADCO, Fluted Westbrooke	18	25.44	(I)
Aluminum, HADCO, Non-Fluted Westbrooke	18	26.97	(I)
Concrete Ameron Post-Top	25	24.12	(R)

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

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)

Type of Pole	Pole Length (feet)	Monthly Rate Per Pole	
Rates for Area Light Poles[1]			
Fiberglass Fluted Ornamental; Black	14	14.86	**(R)**
Fiberglass, Regular			
Black	20	6.18	
Gray or Bronze	30	10.50	
Other Colors (as available)	35	9.04	
Fiberglass, Anchor Base Gray	35	16.51	
Fiberglass, Direct Bury with Shroud	18	9.96	**(R)**

INSTALLATION CHARGE

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

ADJUSTMENTS

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

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

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			(I)
Single Phase Service	$15.00		(I)
Three Phase Service	$20.00		
Transmission and Related Services Charge	0.222	¢ per kWh	(R)
Distribution Charge			
First 5,000 kWh	3.983	¢ per kWh	(I)
Over 5,000 kWh	1.027	¢ per kWh	(I)
Energy Charge Options			
Standard Service	5.825	¢ per kWh	(R)
or			
Time-of-Use (TOU) Portfolio (enrollment is necessary)			
On-Peak Period	10.251	¢ per kWh	
Mid-Peak Period	5.825	¢ per kWh	
Off-Peak Period	3.419	¢ 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 Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index)
- plus 0.302 ¢ per kWh for wheeling (I)
- times a loss adjustment factor of 1.0685 (R)

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, 2015. **(C)**

MONTHLY RATE

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

Basic Charge			
Single Phase Service	$25.00		
Three Phase Service	$25.00		
Transmission and Related Services Charge	0.210	¢ per kWh	**(R)**
Distribution Charge	6.657	¢ per kWh	**(I)**
Energy Charge*			
On-Peak Period	6.288	¢ per kWh	**(R)**
Off-Peak Period	5.288	¢ per kWh	**(R)**

* 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 Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.302¢ 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 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:

Secondary Delivery Voltage 1.0685 **(R)**

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**	$35.00		(I)
Winter Months**	No Charge		
Transmission and Related Services Charge	0.342	¢ per kWh	
Distribution Charge			
First 50 kWh per kW of Demand***	8.232	¢ per kWh	
Over 50 kWh per kW of Demand	6.232	¢ per kWh	
Energy Charge	7.246	¢ 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**	$40.00		(I)
Winter Months**	No Charge		
Transmission and Related Services Charge	0.310	¢ per kWh	(R)
Distribution Charge			
First 50 kWh per kW of Demand***	6.147	¢ per kWh	(I)
Over 50 kWh per kW of Demand	4.147	¢ per kWh	
Energy Charge	6.866	¢ 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	$5,440.00	$4,870.00	$5,600.00	(I)
Transmission and Related Services Charge				
per kW of monthly On-Peak Demand	$0.84	$0.82	$0.81	(R)
Distribution Charges				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.97	$1.94	$1.94	(I)
Over 4,000 kW	$1.50	$1.47	$1.47	(I)
per kW of monthly On-Peak Demand	$2.24	$2.20	$0.83	(I)(R)
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	0.085` ¢	0.082 ¢	0.080 ¢	(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 Powerdex Mid-Columbia Hourly Firm Electricity Price Index (Powerdex-Mid-C Hourly Firm Index) plus 0.302¢ per kWh for wheeling, a 0.300¢ per kWh recovery **(I)**
factor, plus losses.

SCHEDULE 75 (Continued)

ENERGY CHARGE (Continued)

Unscheduled Energy (Continued)

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.

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.

The Company may request that a Customer taking Unscheduled Energy during more than 1,000 hours during a calendar year provide information detailing the reasons that the generator was not able to run during those hours in order to determine the appropriate Baseline Demand.

LOSSES

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

Subtransmission Delivery Voltage	1.0356	**(I)**
Primary Delivery Voltage	1.0496	**(I)**
Secondary Delivery Voltage	1.0685	**(R)**

DIRECT ACCESS PARTIAL REQUIREMENTS SERVICE

A Customer served under this schedule may elect to receive Direct Access Partial Requirements Service from an Electricity Service Supplier (ESS) under the terms of Schedule 575 provided it has given notice consistent with any Baseline Energy option requirements. A Customer may return to Schedule 75 provided it has met any term requirements of Schedule 575 and any requirements needed to purchase Baseline Energy if needed.

MINIMUM CHARGE

The Minimum Charge will be the Basic, Transmission, Distribution, Demand and Generation Contingency Reserves Charges, when applicable. In addition, the Company may require a higher Minimum Charge, if necessary, to justify the Company's investment in service Facilities.

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 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	$0.033	$0.032	$0.032	**(R)**
Daily ERP Demand Charge				
per kW of Daily ERP Demand during On-Peak hours per day**	$0.087	$0.086	$0.032	**(I)(R)** **(D)**
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 Powerdex Mid-Columbia Hourly Price Index (Powerdex-Mid-C Hourly Index) plus a 5% adder, which will not be less than 0.15¢ per kWh, plus 0.302¢ 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 0.302¢ 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 0.302¢ 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	1.0356	(I)
Primary Delivery Voltage	1.0496	(I)
Secondary Delivery Voltage	1.0685	(R)

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 Powerdex Mid-Columbia Hourly Price Index (Powerdex-Mid-C Hourly Index), plus 0.302¢ 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 Powerdex-Mid-C Hourly Index plus 0.302¢ 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 Powerdex Mid-Columbia Hourly Price Index (Powerdex-Mid-C Hourly Index), plus 10%, plus 0.302¢ per kWh for wheeling, plus losses. **(I)**

For negative excess Imbalance Energy, the excess Energy Imbalance is multiplied by the Settlement Price of the Powerdex-Mid-C Hourly Index, less 10%, plus 0.302¢ per kWh for wheeling, plus losses. **(I)**
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 Intercontinental Exchange Mid-Columbia Daily on- and off-peak Firm Electricity Price Index (ICE-Mid-C Firm Index) plus 0.302¢ per kWh **(I)** 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.

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	1.0356	**(I)**
Primary Delivery Voltage	1.0496	**(I)**
Secondary Delivery Voltage	1.0685	**(R)**

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 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. 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	
Three Phase Service	$40.00	
Transmission and Related Services Charge		
per kW of monthly On-Peak Demand	$0.84	(R)
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 30 kW	$2.96	(I)
Over 30 kW	$2.86	
per kW of monthly On-Peak Demand	$2.24	(I)
Energy Charge ***		
On-Peak Period***	6.159 ¢	(R)
Off-Peak Period***	5.159 ¢	
See below for Daily Pricing Option description.		
System Usage Charge		
per kWh	0.672 ¢	(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 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 Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.302¢ 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:

Secondary Delivery Voltage 1.0685 **(R)**

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)

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 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 Demand 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.

MONTHLY RATE

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

	Delivery Voltage Secondary	Delivery Voltage Primary	
Basic Charge	$470.00	$500.00	(R)
Transmission and Related Services Charge			
per kW of monthly On-Peak Demand	$0.84	$0.82	(R)
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 200 kW	$3.09	$3.04	(I)
Over 200 kW	$2.19	$2.14	
per kW of monthly On-Peak Demand	$2.24	$2.20	(I)
Energy Charge			
On-Peak Period***	5.985 ¢	5.881 ¢	(R)
Off-Peak Period***	4.985 ¢	4.881 ¢	
See below for Daily Pricing Option description.			
System Usage Charge			
per kWh	0.114 ¢	0.110 ¢	(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 Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.302¢ 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	1.0496	**(I)**
Secondary Delivery Voltage	1.0685	**(R)**

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
(>4,000 kW)

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.

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	$5,440.00	$4,870.00	$5,600.00	(I)
Transmission and Related Services Charge				
per kW of monthly On-Peak Demand	$0.84	$0.82	$0.81	(R)
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.97	$1.94	$1.94	(I)
Over 4,000 kW	$1.50	$1.47	$1.47	(I)
per kW of monthly On-Peak Demand	$2.24	$2.20	$0.83	(I)(R)
Energy Charge				
On-Peak Period***	5.725 ¢	5.629 ¢	5.557 ¢	(R)
Off-Peak Period***	4.725¢	4.629 ¢	4.557 ¢	
See below for Daily Pricing Option description.				
System Usage Charge				
Per kWh	0.085 ¢	0.082 ¢	0.080 ¢	(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 Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.302¢ 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:

Subtransmission Delivery Voltage	1.0356	**(I)**
Primary Delivery Voltage	1.0496	**(I)**
Secondary Delivery Voltage	1.0685	**(R)**

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 90
LARGE NONRESIDENTIAL
STANDARD SERVICE
(>4,000 kW and Aggregate to >100 MWa)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer who meet the following conditions: 1) Individual account 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 2) where combined usage of all accounts meeting condition 1 for the Large Nonresidential Customer aggregate to at least 100 MWa in a calendar year; and 3) the customer maintains a load factor of 80% or greater for each account.

MONTHLY RATE

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

Basic Charge	$25,000.00	**(I)**
Transmission and Related Services Charge		
per kW of monthly On-Peak Demand	$0.82	**(R)**
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 4,000 kW	$1.08	**(R)**
Over 4,000 kW	$1.08	**(R)**
per kW of monthly On-Peak Demand	$2.20	**(I)**
Energy Charge		
On-Peak Period***	5.488 ¢	**(R)**
Off-Peak Period***	4.488 ¢	
See below for Daily Pricing Option description.		
System Usage Charge		
Per kWh	0.071 ¢	**(R)(C)**

* 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 90 (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 Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.302¢ 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:

Subtransmission Delivery Voltage	1.0356	**(I)**
Primary Delivery Voltage	1.0496	**(I)**
Secondary Delivery Voltage	1.0685	**(R)**

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 90 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 90 (Concluded)

ADJUSTMENTS

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

(D)

TERM

Service will be for not less than one year or as otherwise provided under this Schedule.

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	0.176 ¢ per kWh	**(R)**
Distribution Charge	4.781 ¢ per kWh	**(I)**
Energy Charge		
Cost of Service Option	4.966 ¢ 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 Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.302¢ 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 1.0685. **(R)**

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	*	$ 1.36	(I)
	100	9,500	43	*	1.38	
	150	16,000	62	*	1.38	
	200	22,000	79	*	1.44	
	250	29,000	102	*	1.46	
	400	50,000	163	*	1.47	
Cobrahead	70	6,300	30	$ 5.05	1.61	(R)
	100	9,500	43	4.99	1.60	
	150	16,000	62	5.02	1.61	(R)
	200	22,000	79	5.76	1.68	(I)
	250	29,000	102	5.73	1.68	(R)
	400	50,000	163	6.14	1.73	
Flood	250	29,000	102	6.47	1.77	
	400	50,000	163	6.47	1.77	
Early American Post-Top	100	9,500	43	5.75	1.69	
Shoebox (bronze color, flat lens, or drop lens, multi-volt)	70	6,300	30	6.40	1.78	
	100	9,500	43	6.59	1.80	
	150	16,000	62	6.85	1.84	(I)

* 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	$6.18	$ 0.14	
Fiberglass, Bronze	30	9.74	0.22	(I)
Fiberglass, Gray	30	10.50	0.24	
Wood, Standard	30 to 35	7.03	0.16	
Wood, Standard	40 to 55	9.20	0.21	(R)(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	$ 9.88	$ 2.17	(R)(I)
HADCO Victorian, HPS	150	16,000	62	9.78	2.17	
	200	22,000	79	10.50	2.29	
	250	29,000	102	10.55	2.29	
HADCO Capitol Acorn, HPS	100	9,500	43	13.60	2.63	
	150	16,000	62	13.54	2.67	
	200	22,000	79	13.52	2.66	
	250	29,000	102	13.54	2.67	
Special Architectural Types						
HADCO Independence, HPS	100	9,500	43	9.88	2.15	
	150	16,000	62	9.59	2.13	
HADCO Techtra, HPS	100	9,500	43	18.55	3.23	
	150	16,000	62	18.06	3.18	
	250	29,000	102	17.45	3.14	
HADCO Westbrooke, HPS	70	6,300	30	12.62	2.50	
	100	9,500	43	12.39	2.47	
	150	16,000	62	12.40	2.48	
	200	22,000	79	12.66	2.54	
	250	29,000	102	12.51	2.53	(R)(I)

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	$ 5.65	$ 1.94	**(R)(I)**
Flood, Metal Halide	350	30,000	139	7.79	2.22	
Flood, HPS	750	105,000	285	9.40	2.71	
Holophane Mongoose, HPS	150	16,000	62	10.23	2.22	
	250	29,000	102	9.58	2.16	**(R)(I)**
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	$8.39	$ 0.19	**(R)(I)**
	25	13.93	0.31	
	30	15.05	0.34	**(I)**
	35	18.00	0.40	
Aluminum Davit	25	13.90	0.31	**(I)**
	30	13.83	0.31	
	35	15.12	0.34	
	40	20.52	0.46	
Aluminum Double Davit	30	20.42	0.46	**(R)(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	$12.29	$ 0.28	(R)(I)
Aluminum, HADCO, Non-Fluted Techtra Ornamental	18	24.18	0.54	(I)
Aluminum, HADCO, Fluted Ornamental	16	12.56	0.28	
Aluminum, HADCO, Non-Fluted Ornamental	16	25.69	0.58	(I)
Aluminum, HADCO, Fluted Westbrooke	18	24.24	0.54	
Aluminum, HADCO, Non-Fluted Westbrooke	18	25.69	0.58	
Aluminum, Painted Ornamental	35	41.28	0.92	
Concrete. Decorative Ameron	20	24.12	0.54	
Concrete, Ameron Post-Top	25	24.12	0.54	(I)
Fiberglass, HADCO, Fluted Ornamental Black	14	14.86	0.33	
Fiberglass, Smooth	18	6.16	0.14	
Fiberglass, Regular				
color may vary	22	5.51	0.12	
	35	9.04	0.20	
Fiberglass, Anchor Base, Gray	35	16.51	0.37	(I)
Fiberglass, Direct Bury with Shroud	18	9.96	0.22	(R)

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	$ 4.94	$ 1.55	(R)(I)
	250	10,000	94	*	*	
	400	21,000	147	5.76	1.68	
	1,000	55,000	374	6.42	2.01	(R)
Special Box Similar to GE "Space-Glo"						
HPS	70	6,300	30	6.49	1.70	
Mercury Vapor	175	7,000	66	6.44	1.65	(R)(I)

* 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	*	$ 2.06	(I)
	150	16,000	62	*	2.08	(I)
	250	29,000	102	*	*	
	400	50,000	163	*	*	
Metal Halide	250	20,500	99	*	1.28	(I)
	400	40,000	156	*	1.28	
Cobrahead, Metal Halide	175	12,000	71	$ 5.88	1.77	(R)
Flood, Metal Halide	400	40,000	156	6.67	1.81	(R)
Cobrahead, Dual Wattage, HPS						
70/100 Watt Ballast	100	9,500	43	*	1.61	
100/150 Watt Ballast	100	9,500	43	*	1.61	
100/150 Watt Ballast	150	16,000	62	*	1.63	
Special Architectural Types Including Philips QL Induction Lamp Systems						
HADCO Victorian, QL	85	6,000	32	*	0.77	
	165	12,000	60	*	1.04	
HADCO Techtra, QL	165	12,000	60	21.86	1.23	(R)
Special Architectural Types						
KIM SBC Shoebox, HPS	150	16,000	62	*	2.64	
KIM Archetype, HPS	250	29,000	102	*	2.87	
	400	50,000	163	*	2.27	
Special Acorn-Type, HPS	70	6,300	30	9.85	2.14	(R)(I)
Special GardCo Bronze Alloy						
HPS	70	5,000	30	*	*	
Mercury Vapor	175	7,000	66	*	*	
Special Acrylic Sphere						
Mercury Vapor	400	21,000	147	*	*	

* 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	$ 5.64	$ 1.58	(R)(I)
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	5.65	1.59	(R)(I)
Flood, HPS	70	6,300	30	4.87	1.48	(R)
	100	9,500	43	5.03	1.60	(I)
	200	22,000	79	6.45	1.75	
Cobrahead, HPS						
Power Door	310	37,000	124	6.13	2.08	(R)(I)
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.

SCHEDULE 91 (Continued)

RATES FOR OBSOLETE LIGHTING POLES

Type of Pole	Poles Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Aluminum Post	30	$ 8.39	*	**(R)**
Bronze Alloy GardCo	12	*	$ 0.17	
Concrete, Ornamental	35 or less	13.93	0.31	**(R)**
Steel, Painted Regular **	25	13.93	0.31	
Steel, Painted Regular **	30	15.05	0.34	**(R)(I)**
Steel, Unpainted 6-foot Mast Arm **	30	*	0.31	
Steel, Unpainted 6-foot Davit Arm **	30	*	0.31	
Steel, Unpainted 8-foot Mast Arm **	35	*	0.34	
Steel, Unpainted 8-foot Davit Arm **	35	*	0.34	**(I)**
Wood, Laminated without Mast Arm	20	6.18	0.14	**(R)**
Wood, Laminated Street Light Only	20	6.18	*	
Wood, Curved Laminated	30	9.74	0.22	**(I)**
Wood, Painted Underground	35	7.03	0.16	**(I)**
Wood, Painted Street Light Only	35	7.03	*	**(R)**

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

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 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	0.175	¢ per kWh	**(R)**
Distribution Charge	2.110	¢ per kWh	**(I)**
Energy Charge	5.194	¢ 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 (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	0.176 ¢ per kWh	(R)
Distribution Charge	4.781 ¢ per kWh	(I)
Energy Charge		
Cost of Service Option	4.966 ¢ 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 Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.302¢ 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 1.0685. (R)

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
	$122.00 per hour	$163.00 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	
Cobrahead Equivalent	37	2,530	13	$ 3.36	(R)
Cobrahead Equivalent	50	3,162	17	3.36	
Cobrahead Equivalent	52	3,757	18	3.75	
Cobrahead Equivalent	67	5,050	23	4.18	
Cobrahead Equivalent	106	7,444	36	4.99	

RATES FOR DECORATIVE LIGHTING

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rate Option A	
Acorn LED	60	5,488	21	$12.19	
	70	4,332	24	14.07	
Westbrooke (Non-Flared)	49	5,094	17	16.97	
LED	69	6,680	24	17.74	
	109	8,176	37	18.01	
	136	12,728	46	21.66	
	206	18,159	70	21.66	
Westbrooke (Flared)	49	5,094	17	19.09	
LED	69	6,680	24	19.44	
	109	8,176	37	20.10	
	136	12,728	46	22.97	
	206	18,159	70	22.97	(R)

SCHEDULE 100
SUMMARY OF APPLICABLE ADJUSTMENTS

The following summarizes the applicability of the Company's adjustment schedules.

Schs.	102 (1)	105	106 (1)	108 (3)	109 (1)	110 (1)	115	122	123 (1)	125 (1)	126	128 (4)	129 (1)	135	137	142	143	144	145	(N)
7	x	x	x	x	x	x	x	x	x	x	x			x	x	x	x	x	x	
12	x	x	x	x	x	x	x	x	x	x	x			x	x	x	x	x	x	
15	x	x	x	x	x	x	x	x	x	x	x			x	x	x	x	x	x	
32	x	x	x	x	x	x	x	x	x	x	x	x		x	x	x	x	x	x	
38	x	x	x	x	x	x	x	x	x	x	x	x		x	x	x	x	x	x	
47	x	x	x	x	x	x	x	x	x	x	x			x	x	x	x	x	x	
49	x	x	x	x	x	x	x	x	x	x	x			x	x	x	x	x	x	
75	x(2)	x(2)	x	x	x(2)	x(2)	x	x(2)	x	x(2)	x(2)	x		x	x	x	x	x	x	
76R	x		x	x			x									x				(C)
83	x	x	x	x	x	x	x	x	x	x	x	x		x	x	x	x	x	x	
85	x	x	x	x	x	x	x	x	x	x	x	x		x	x	x	x	x	x	
89	x	x	x	x	x	x	x	x	x	x	x	x		x	x	x	x	x	x	
90	x	x	x	x	x	x	x	x	x	x	x	x		x	x	x	x	x	x	
91		x	x	x	x	x	x	x	x	x	x	x		x	x	x	x	x	x	
92		x	x	x	x	x	x	x	x	x	x			x	x	x	x	x	x	
95		x	x	x	x	x	x	x	x	x	x	x		x	x	x	x	x	x	
485	x	x	x	x	x	x	x		x		x(5)		x			x	x	x		
489	x	x	x	x	x	x	x		x		x(5)		x			x	x	x		
490	x	x	x	x	x	x	x		x		x		x			x	x	x		
491		x	x	x	x	x	x		x		x		x			x	x	x		
492		x	x	x	x	x	x		x		x		x			x	x	x		
495		x	x	x	x	x	x		x		x		x			x	x	x		
515	x	x	x	x	x	x	x		x		x(5)	x			x	x	x	x	x	
532	x	x	x	x	x	x	x		x		x(5)	x			x	x	x	x	x	
538	x	x	x	x	x	x	x		x		x(5)	x			x	x	x	x	x	
549	x	x	x	x	x	x	x		x		x(5)	x			x	x	x	x	x	
575	x(2)	x(2)	x	x	x	x	x		x		x(2)	x			x	x	x	x	x	
576R	x		x	x			x									x				(C)
583	x	x	x	x	x	x	x		x		x(5)	x			x	x	x	x	x	
585	x	x	x	x	x	x	x		x		x(5)	x			x	x	x	x	x	
589	x	x	x	x	x	x	x		x		x(5)	x			x	x	x	x	x	
590	x	x	x	x	x	x	x		x		x	x			x	x	x	x	x	
591		x	x	x	x	x	x		x		x(5)	x			x	x	x	x	x	
592		x	x	x	x	x	x		x		x(5)	x			x	x	x	x	x	
595		x	x	x	x	x	x		x		x(5)	x			x	x	x	x	x	(N)

(1) Where applicable.
(2) These adjustments are applicable only to the Baseline and Scheduled Maintenance Energy.
(3) Schedule 108 applies to the sum of all charges less taxes, Schedule 109 and 115 charges and one-time charges such as deposits.
(4) Applicable to Nonresidential Customer who receive service at Daily pricing (other than Cost of Service) or Direct Access (excluding service on Schedules 485, 489, 490, 491, 492 and 495).
(5) Not applicable to Customers where service was received for the entire calendar year that the Annual Power Cost Variance accrued.

SCHEDULE 102
REGIONAL POWER ACT EXCHANGE* CREDIT

PURPOSE

Each Customer's bill rendered under schedules providing Residential Service, Farm Service and Nonresidential Farm Irrigation and Drainage Pumping Service will include the Regional Power Act Exchange Credit applied to each kWh sold when the Customer qualifies for the adjustment according to the definitions and limitations set forth in this schedule. Where Customers are served by Electricity Service Suppliers (ESSs), the ESS will agree to pass through the credit to the Customer.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all bills for Direct Access Service, Emergency Default Service, Standard Service and Residential Service where the Customer meets the definition of Residential Service, Farm Service or Farm Irrigation and Drainage Pumping Service as specified in this schedule.

REGIONAL POWER ACT EXHANGE CREDIT

The credit will be the value of power and other benefits inclusive provided in accordance with the terms of the Settlement Agreement between the Company and the Bonneville Power Administration (BPA).

The credit inclusive of interest is:

Schedule 7				
	First 1,000 kWh	0.889	¢ per kWh	**(R)**
	Over 1,000 kWh	0.000	¢ per kWh	
All other schedules		0.730	¢ per kWh	**(R)**

RESIDENTIAL SERVICE

Residential Service means Electricity Service provided for residential purposes including service to master-metered apartments, apartment utility rooms, common areas, and other residential uses.

* Short title for "Pacific Northwest Electric Power Planning and Conservation Act".

SCHEDULE 122
RENEWABLE RESOURCES AUTOMATIC ADJUSTMENT CLAUSE

PURPOSE

This Schedule recovers the revenue requirements of qualifying Company-owned or contracted new renewable energy resource projects (including associated transmission) not otherwise included in rates. Additional new renewable projects may be incorporated into this schedule as they are placed in service. This Schedule also recovers or refunds differences between the projected costs of qualifying renewable resources made in a ratemaking process and the actual costs incurred. This adjustment schedule is implemented as an automatic adjustment clause as provided for under ORS 757.210 and Section 13 of the Oregon Renewable Energy Act (OREA). **(C)** **(C)**

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all bills for Electricity Service except Schedules 76, 485, 489, 490, 491, 492, 495 and 576. This schedule is not applicable to direct access customers after December 31, 2010.

ADJUSTMENT RATE

The Adjustment Rate, applicable for service on and after the effective date of this schedule are:

Schedule		
7	0.000	¢ per kWh
15	0.000	¢ per kWh
32	0.000	¢ per kWh
38	0.000	¢ per kWh
47	0.000	¢ per kWh
49	0.000	¢ per kWh
75		
Secondary	0.000	¢ per kWh
Primary	0.000	¢ per kWh
Subtransmission	0.000	¢ per kWh
83	0.000	¢ per kWh
85		
Secondary	0.000	¢ per kWh
Primary	0.000	¢ per kWh

SCHEDULE 122 (Continued)

QUALIFYING RESOURCE COST VARIANCE TRUE-UP (N)

Annually, the variances between the costs projected in either a general rate-making process or through the Schedule 125 Annual Power Cost Update and the actual costs of qualifying renewable resources will be calculated and subject to collection or refund through this Schedule. The calculation of these collections or refunds will be based upon the variances in energy output value, production tax credits, integration costs, and royalties for RPS-compliant resources. For qualifying resources owned by PGE, the cost variance will be calculated by comparing the projections made of the hourly generation, hourly prices, monthly royalty payments, and monthly integration costs to the actual hourly generation, the actual hourly prices as reported by the PowerDex Mid-Columbia Hourly Price Index, the actual monthly royalty payments, and the actual integration costs. For contracted qualifying resources, the variance will be calculated by comparing the projections made of the monthly generation and contract prices to the actual monthly generation and contract price. The filing for these collections or refunds will occur at the same time as the filing for the Schedule 126 Annual Power Cost Variance Mechanism. (N)

TIME AND MANNER OF FILING

For each calendar year that the Company is required to update the Renewable Resource Annual Revenue Requirements or proposes to include a new resource under this schedule, the Company will file by no later than April 1, the following:

1. Revised rates under this schedule and a transmittal letter that summarizes the proposed revenue requirements and charges for both the new resource(s) and the updated revenue requirements and charges for applicable resources previously approved for recovery under this schedule. In addition, the filing will include revised income taxes and associated ratios to calculate “taxes authorized to be collected in rates” under ORS 757.268.

2. Within the Company’s Annual Power Cost Update (Schedule 125) filing, the Company will include for the following year the expected generation of resources included in this schedule and the power costs of these resources.

3. Work papers that support the calculation of revenue requirements for all applicable resources and demonstrate how the proposed prices are calculated.

By December 1, the Company will file the updated rates that are in compliance with the Commission’s findings in the proceeding reviewing the April 1 filing.

(M)

SCHEDULE 122 (Concluded)

SPECIAL CONDITIONS **(T)**

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. **(M)**

2. Each renewable resource project (and associated transmission) included in this adjustment schedule must be separately identified and be a new resource defined as "renewable" in the OREA.

3. The costs for projects included under this schedule will be updated annually as provided above, and will continue to be recovered under Schedule 122 until such time as the costs are included in base rates or the project is no longer in service.

4. The in-service date for the new renewable resource project or each separately identifiable project segment will be verified by an attestation from the Company stating that the specific renewable resource project, or project segment, has met requirements for being commercially operational and is in service. **(M)**

   If the actual costs of an eligible resource cannot be verified by the final round of testimony in the proceeding reviewing the April 1 filing, the Company will include in its December 1 compliance filing an update to reflect then-current actual resource costs, or forecasted costs where appropriate. If the updated costs are lower than the projected costs in the record of the proceeding, the update will contain sufficient information to support a reduction in the proposed adjustment charges before the January 1 effective date. If updated costs are higher than the projected costs in the record or if actual costs cannot be verified until after December 1, the Company may file for deferred accounting under the OREA to allow an opportunity for recovery of the cost differences between the projected costs in the record and the prudently incurred actual costs. **(T)** **(D)**

5. For Schedule 122 filings made on and after April 2009, the Commission may condition approval of a proposed change in Schedule 122 charges on PGE making a filing under ORS 757.210 within six months after the Commission order approving the proposed change. Through this filing, the Company will roll into the generation component of its rates all of the costs, or a portion thereof identified by the Commission, that are being collected through the then existing Schedule 122 charges. The Commission's order for conditional approval must be based upon: (1) a finding that the costs, or a portion thereof, specified by the Commission have been collected through Schedule 122 for a reasonable period of years, as determined by the Commission; or (2) for good cause, as determined by the Commission. **(T)**

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 6.659 cents/kWh for Schedule 7 **(I)**
and 6.082 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 $55.96 per month for Schedule 7 and $88.17 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. For Schedule 7, a Secondary Fixed Charge equal to 75% of the Monthly Fixed **(C)**
Charge will be used to calculate Fixed Charge Revenues for actual customer counts that exceed the projected customer counts used to establish base rates in a general rate review. The Schedule 7 Secondary Fixed Charge is $41.97. **(I)**

SCHEDULE 123 (Continued)

SALES NORMALIZATION ADJUSTMENT (SNA) (Continued)

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.

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.

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 4.489 **(I)**
cents per kWh.

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, 90, 91, 92, and 95. Customers served under the daily price option contained in schedules 32, 38, 75, 81, 83, 85, 89, 90, 91, and 95 are exempt from Schedule 125.

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.

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.
- Costs associated with wind integration.
- Forward market prices for both gas and electricity.
- Projected loads.
- Contracts for the purchase or sale of power and fuel.
- Emission control chemical costs.
- Thermal plant variable operation and maintenance, including the cost of transmission losses, for dispatch purposes.
- Changes in hedges, options, and other financial instruments used to serve retail load.
- Transportation contracts and other fixed transportation costs.
- Reciprocating engine lubrication oil costs. **(C)**
- No other changes or updates will be made in the annual filings under this schedule.

Schedule 126 (Continued)

DEFINITIONS

Actual Loads

Actual loads are total annual calendar retail loads adjusted to exclude loads of Customers to whom this adjustment schedule does not apply.

Actual NVPC

Incurred cost of power based on the definition for NVPC described here in. Actual NVPC will be increased by 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. Actual NVPC will be reduced by the **(C)**
costs associated with qualifying renewable resources. **(C)**

Actual Unit NVPC

The Actual Unit NVPC is the Actual NVPC divided by Actual Loads.

Annual Variance (AV)

The Annual Variance (AV) is the dollar amount calculated annually based on the following formula:

(Actual Unit NVPC – Adjusted Base Unit NVPC) * Actual Loads

Base Unit NVPC

The Base Unit NVPC is the NVPC used to develop rate schedules for the applicable year divided by the associated calendar basis retail loads. Base NVPC are updated annually in accordance with Schedule 125. Base Unit NVPC will be reduced by the projected costs of **(C)**
qualifying renewable resources. **(C)**

Adjusted Base Unit NVPC

The Adjusted Base Unit NVPC is the NVPC used to calculate the Annual Variance. The Adjusted Base Unit NVPC is the Base Unit NVPC (determined in accordance with Schedule 125) adjusted for load and cost changes resulting from non-residential customers choosing service under Schedule 515 through 595 after the November update for the applicable year.

Negative Annual Power Cost Deadband

The Negative Annual Power Cost Deadband is ($15.0 million).

Positive Annual Power Cost Deadband

The Positive Annual Power Cost Deadband is $30.0 million.

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:

- 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, 90, and 91 Energy pricing options other than Cost of Service and the Energy Charge revenues from the Market Based Pricing Option from Schedules 485, 489, 490, 491, 492, and 495 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.
- Include reciprocating expense lubrication oil expenses. **(C)**

ADJUSTMENT AMOUNT

The amount accruing to the Power Cost Variance Account, whether positive or negative will be multiplied by a revenue sensitive factor of 1.0331 to account for franchise fees, uncollectables, and OPUC fees.

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 126 (Continued)

TIME AND MANNER OF FILING (Continued)

Included in this filing will be the following information:

1) A transmittal letter that summarizes the proposed changes.
2) Revised Power Cost Variance Rates.
3) Work papers supporting the calculation of the revised PCV rates.
4) The proposed Schedule 122 Qualifying Resource Cost Variance True-up **(C)**

If the Company finds that the PCV Rates may over or under collect revenues in a particular year, the Company may recommend a modification of the Adjustment Rates to the Commission. The Company may also recommend that the Commission consider Adjustment Rates based on a collection or refund period different than one year based on the balance in the PCV Account.

POWER COST VARIANCE RATES

The PCV Rates will be determined on an equal cents per kWh basis. The PCV Rates are:

Schedule	Adjustment Rate
7	0.000 ¢ per kWh
15	0.000 ¢ per kWh
32	0.000 ¢ per kWh
38	0.000 ¢ per kWh
47	0.000 ¢ per kWh
49	0.000 ¢ per kWh
75	
Secondary	0.000 ¢ per kWh(1)
Primary	0.000 ¢ per kWh(1)
Subtransmission	0.000 ¢ per kWh(1)
83	0.000 ¢ per kWh
85	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
89	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh

(1) Applicable only to the Baseline and Scheduled Maintenance Energy.
(2) Not applicable to Customers where service was received for the entire calendar year that the Annual Power Cost Variance accrued.

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, 90, 91 or 95 or Direct Access service on Schedules 515, 532, 538, 549, 575, 583, 585, 589, 590, 591, 592 and 595. This Schedule is not applicable to Customers served on Schedules 485, 489, 490, 491, 492 and 495.

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 2014, the Annual Short-Term Transition Adjustment Rate will be applied to their bills for service effective on and after January 1, 2015: **(C)**
(C)

Schedule		Annual ¢ per kWh [1]	
32		2.018	**(R)**
38		1.883	
75	Secondary	1.563 [2]	
	Primary	1.533 [2]	
	Subtransmission	1.510 [2]	
83		1.987	
85	Secondary	1.819	
	Primary	1.790	
			(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	1.563	(R)
	Primary	1.533	
	Subtransmission	1.510	
90		1.386	
91		1.435	
95		1.435	
515		1.435	
532		2.018	
538		1.883	
549		3.023	
575	Secondary	1.563 [(2)]	
	Primary	1.533 [(2)]	
	Subtransmission	1.510 [(2)]	
583		1.987	
585	Secondary	1.819	
	Primary	1.790	
589	Secondary	1.563	
	Primary	1.533	
	Subtransmission	1.510	
590		1.386	
591		1.435	
592		1.463	
595		1.435	(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
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
90		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
590		0.000
591		0.000
592		0.000
595		0.000

(1) Applicable April 1, 2015 through December 31, 2015. (C)
(2) Not applicable to Customers served on Cost of Service.
(3) Applicable only to the Baseline and Scheduled Maintenance Energy.

SCHEDULE 143
SPENT FUEL ADJUSTMENT

PURPOSE

The purpose of this schedule is to implement in rates the amortization of the excess funds previously contained in the Trojan Nuclear Decommissioning Trust Fund and the pollution control tax credits associated with the Independent Spent Fuel Storage Installation at the Trojan nuclear plant.

APPLICABLE

To all bills for Electricity Service calculated under all schedules and contracts, except those Customers explicitly exempted.

PART A – TROJAN NUCLEAR DECOMMISSIONING TRUST FUND

Part A consists of the amortization of the excess funds previously contained in the Trojan Nuclear Decommissioning Trust Fund.

PART B – ISFSI ADJUSTMENT

Part B consists of the amortization of the payments from the Oregon Department of Energy related to state pollution control tax credits for the Independent Spent Fuel Storage Installation at Trojan.

ADJUSTMENT RATES

The Adjustment Rates, applicable for service on and after the effective date of this schedule, will be:

Schedule	Part A	Part B	Adjustment Rate	
7	(0.096)	(0.031)	(0.127)	¢ per kWh
15	(0.076)	(0.025)	(0.101)	¢ per kWh
32	(0.089)	(0.029)	(0.118)	¢ per kWh
38	(0.089)	(0.029)	(0.118)	¢ per kWh
47	(0.111)	(0.036)	(0.147)	¢ per kWh
49	(0.105)	(0.034)	(0.139)	¢ per kWh
75				
Secondary	(0.082)	(0.027)	(0.109)	¢ per kWh(1)
Primary	(0.080)	(0.026)	(0.106)	¢ per kWh(1)
Subtransmission	(0.079)	(0.026)	(0.105)	¢ per kWh(1)

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

SCHEDULE 143 (Continued)

ADJUSTMENT RATES (Continued)

Schedule	Part A	Part B	Adjustment Rate	
83	(0.089)	(0.029)	(0.118)	¢ per kWh
85				
Secondary	(0.086)	(0.028)	(0.114)	¢ per kWh
Primary	(0.084)	(0.027)	(0.111)	¢ per kWh
89				
Secondary	(0.082)	(0.027)	(0.109)	¢ per kWh
Primary	(0.080)	(0.026)	(0.106)	¢ per kWh
Subtransmission	(0.079)	(0.026)	(0.105)	¢ per kWh
90	(0.078)	(0.025)	(0.103)	¢ per kWh
91	(0.076)	(0.025)	(0.101)	¢ per kWh
92	(0.080)	(0.026)	(0.106)	¢ per kWh
95	(0.076)	(0.025)	(0.101)	¢ per kWh
485				
Secondary	(0.086)	(0.028)	(0.114)	¢ per kWh
Primary	(0.084)	(0.027)	(0.111)	¢ per kWh
489				
Secondary	(0.082)	(0.027)	(0.109)	¢ per kWh
Primary	(0.080)	(0.026)	(0.106)	¢ per kWh
Subtransmission	(0.079)	(0.026)	(0.105)	¢ per kWh
490	(0.078)	(0.025)	(0.103)	¢ per kWh
491	(0.076)	(0.025)	(0.101)	¢ per kWh
492	(0.080)	(0.026)	(0.106)	¢ per kWh
495	(0.076)	(0.025)	(0.101)	¢ per kWh

SCHEDULE 143 (Concluded)

ADJUSTMENT RATES (Continued)

Schedule	Part A	Part B	Adjustment Rate	
515	(0.076)	(0.025)	(0.101)	¢ per kWh
532	(0.089)	(0.029)	(0.118)	¢ per kWh
538	(0.089)	(0.029)	(0.118)	¢ per kWh
549	(0.105)	(0.034)	(0.139)	¢ per kWh
575				
Secondary	(0.082)	(0.027)	(0.109)	¢ per kWh(1)
Primary	(0.080)	(0.026)	(0.106)	¢ per kWh(1)
Subtransmission	(0.079)	(0.026)	(0.105)	¢ per kWh(1)
583	(0.089)	(0.029)	(0.118)	¢ per kWh
585				
Secondary	(0.086)	(0.028)	(0.114)	¢ per kWh
Primary	(0.084)	(0.027)	(0.111)	¢ per kWh
589				
Secondary	(0.082)	(0.027)	(0.109)	¢ per kWh
Primary	(0.080)	(0.026)	(0.106)	¢ per kWh
Subtransmission	(0.079)	(0.026)	(0.105)	¢ per kWh
590	(0.078)	(0.025)	(0.103)	¢ per kWh
591	(0.076)	(0.025)	(0.101)	¢ per kWh
592	(0.080)	(0.026)	(0.106)	¢ per kWh
595	(0.076)	(0.025)	(0.101)	¢ per kWh

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

BALANCING ACCOUNT

The Company will maintain balancing accounts to track the difference between the Trojan Nuclear Decommissioning Trust Fund refund and the ISFSI payments and the actual Schedule 143 revenues. This difference will accrue interest at the Commission-authorized rate for deferred accounts.

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	$470.00	$500.00	(R)
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 200 kW	$3.09	$3.04	(I)
Over 200 kW	$2.19	$2.14	|
per kW of monthly On-Peak Demand	$2.24	$2.20	(I)
System Usage Charge			
per kWh	(0.016) ¢	(0.017) ¢	(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 Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-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 $1.777 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 485 (Continued)

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.

LOSSES

The following adjustment factors will be used where losses are to be included in the Energy Charges:

Primary Delivery Voltage	1.0496	**(I)**
Secondary Delivery Voltage	1.0685	**(R)**

REACTIVE DEMAND CHARGE

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 applicable to this schedule are summarized in Schedule 100.

SPECIAL CONDITIONS

Customers selecting this schedule must enter into a written service agreement. In addition, the Customer acknowledges that:

1. Customer is giving up the right granted under state law to receive Electricity from the Company at a rate based on the cost of electric generating resources owned in whole or in part by the Company. Customers enrolled for service under the minimum Five-Year Option during Enrollment Periods A through L must give the Company not less than two years notice to terminate service under this schedule. Customers enrolled for service under the minimum Five-Year Option subsequent to Enrollment Period L must provide not less than three years notice to terminate service under this schedule. Such notices will be binding.

2. At the time service terminates under this schedule, the Customer will be considered a new Customer for purposes of determining available service options. A Customer served under the Company Supplied Energy option must meet the terms of the service agreement associated with that service prior to termination of service under this schedule.

3. The rate the Customer pays for Electricity may be higher or lower than the rates charged by the Company to similar customers not taking service under this schedule, including competitors to the Customer.

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	$5,440.00	$4,870.00	$5,600.00	**(I)**
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.97	$1.94	$1.94	**(I)**
Over 4,000 kW	$1.50	$1.47	$1.47	**(I)**
per kW of monthly On-Peak Demand	$2.24	$2.20	$0.83	**(I)(R)**
System Usage Charge				
per kWh	(0.036) ¢	(0.036) ¢	(0.037) ¢	**(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 Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-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 $1.777 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 489 (Continued)

LOSSES

The following adjustment factors will be used where losses are to be included in the energy charges:

Subtransmission Delivery Voltage	1.0356	**(I)**
Primary Delivery Voltage	1.0496	**(I)**
Secondary Delivery Voltage	1.0685	**(R)**

REACTIVE DEMAND CHARGE

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 applicable to this schedule are summarized in Schedule 100.

SPECIAL CONDITIONS

Customers selecting this schedule must enter into a service agreement. In addition, the Customer acknowledges that:

1. Customer is giving up the right granted under state law to receive Electricity from the Company at a rate based on the cost of electric generating resources owned in whole or in part by the Company. Customers enrolled for service under the Minimum Five-Year Option during Enrollment Periods A through L must give the Company not less than two years notice to terminate service under this schedule. Customers enrolled for service under the minimum Five-Year Option subsequent to Enrollment Period L must provide not less than three years notice to terminate service under this schedule. Such notices will be binding.

2. At the time service terminates under this schedule, the Customer will be considered a new Customer for purposes of determining available service options. A Customer served under the Company Supplied Energy option must meet the terms of the service agreement associated with that service prior to termination of service under this schedule.

3. The rate the Customer pays for Electricity may be higher or lower than the rates charged by the Company to similar customers not taking service under this schedule, including competitors to the Customer.

SCHEDULE 490 (Continued)

MONTHLY RATE

The Monthly Rate will be the sum of the following charges per Point of Delivery (POD)*: **(C)**

Basic Charge	$25,000.00	**(I)**
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 4,000 kW	$1.08	**(R)**
Over 4,000 kW	$1.08	**(R)**
per kW of monthly On-Peak Demand	$2.20	**(I)**
System Usage Charge		
per kWh	(0.044) ¢	**(R)(C)**

* 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 490 (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 Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-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 $1.777 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 490 (Continued)

LOSSES

The following adjustment factors will be used where losses are to be included in the energy charges:

Subtransmission Delivery Voltage	1.0356	**(I)**
Primary Delivery Voltage	1.0496	**(I)**
Secondary Delivery Voltage	1.0685	**(R)**

REACTIVE DEMAND CHARGE

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 applicable to this schedule are summarized in Schedule 100.

SPECIAL CONDITIONS

Customers selecting this schedule must enter into a service agreement. In addition, the Customer acknowledges that:

(D)

1. Customer is giving up the right granted under state law to receive Electricity from the Company at a rate based on the cost of electric generating resources owned in whole or in part by the Company. Customers enrolled for service under the Minimum Five-Year Option must give the Company not less than three years notice to terminate service under this schedule. Such notice will be binding. **(T)**

2. At the time service terminates under this schedule, the Customer will be considered anew Customer for purposes of determining available service options. A Customer served under the Company Supplied Energy option must meet the terms of the service agreement associated with that service prior to termination of service under this schedule. **(T)**

SCHEDULE 490 (Concluded)

SPECIAL CONDITIONS (Continued)

3. The rate the Customer pays for Electricity may be higher or lower than the rates charged by the Company to similar customers not taking service under this schedule, including competitors to the Customer. **(T)**

4. Neither the Company, its employees and agents, the Commission nor any other agency of the State of Oregon has made any representation to the Customer regarding future Electricity prices that will result from the Customer's election of service under this schedule. **(T)**

5. The Customer is selecting this schedule based solely upon its own analysis of the benefits of this schedule. The Customer has available to it Energy experts that assisted in making this decision. **(T)**

6. The Customer warrants that the person signing the service agreement has full authority to bind the Customer to such agreement. **(T)**

7. Direct Access Service is available only on acceptance of a Direct Access Service Request (DASR) by the Company. A Customer is required to have interval metering and meter communications in place prior to initiation of service under this schedule. **(T)**

8. If the Customer is served at either primary or subtransmission voltage, the Customer will provide, install, and maintain on the Customer's premises all necessary transformers to which the Company's service is directly or indirectly connected. The Customer also will provide, install, and maintain the necessary switches, cutouts, protection equipment, and in addition, the necessary wiring on both sides of the transformers. All transformers, equipment, and wiring will be of types and characteristics approved by the Company, and the arrangement and operation of such equipment will be subject to the approval of the Company. **(T)**

9. Customers selecting service under this Schedule will be limited to a Company/ESS Split Bill. **(T)**

TERM

Minimum Five-Year Option
The term of service will not be less than five years. Service will be year-to-year thereafter. Customers must give the Company not less than three years notice to terminate service under this schedule. Such notice will be binding.

Fixed Three-Year Option
The term of service will be three years. Upon completion of this three year term, the Customer will select service under any other applicable rate schedule, subject to all notice requirements and provisions of the schedule.

SCHEDULE 491 (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 4.650 ¢ per kWh **(I)**

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.

SCHEDULE 491 (Continued)

MARKET BASED PRICING OPTION (Continued)

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.

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 Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-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 $1.777 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.

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.

LOSSES

The following adjustment factors will be used where losses are to be included in the energy charges:

(R)

Secondary Delivery Voltage 1.0685

SCHEDULE 491 (Continued)

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rates (1)	Straight Time	Overtime
	$122.00 per hour	$163.00 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	*	$ 2.76	$ 1.40	(I)(I)
	100	9,500	43	*	3.38	2.00	
	150	16,000	62	*	4.26	2.88	
	200	22,000	79	*	5.11	3.67	
	250	29,000	102	*	6.20	4.74	
	400	50,000	163	*	9.05	7.58	
Cobrahead, Non-Power Door	70	6.300	30	$ 6.45	3.01	1.40	(R) (I)
	100	9,500	43	6.99	3.60	2.00	
	150	16,000	62	7.90	4.49	2.88	
	200	22,000	79	9.43	5.35	3.67	
	250	29,000	102	10.47	6.42	4.74	
	400	50,000	163	13.72	9.31	7.58	
Flood	250	29,000	102	11.21	6.51	4.74	
	400	50,000	163	14.05	9.35	7.58	(I)
Early American Post-Top	100	9,500	43	7.75	3.69	2.00	
Shoebox (Bronze color, flat	70	6,300	30	7.80	3.18	1.40	(R)
Lens, or drop lens, multi-volt)	100	9,500	43	8.59	3.80	2.00	(R)(I)(I)
	150	16,000	62	9.73	4.72	2.88	

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

SCHEDULE 491 (Continued)

RATES FOR STANDARD POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Fiberglass, Black	20	$ 6.18	$0.14	(R)
Fiberglass, Bronze	30	9.74	0.22	(I)
Fiberglass, Gray	30	10.50	0.24	
Wood, Standard	30 to 35	7.03	0.16	
Wood, Standard	40 to 55	9.20	0.21	(R)(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	$11.88	$ 4.17	$ 2.00	(R)(R)(I)
HADCO Victorian, HPS	150	16,000	62	12.66	5.05	2.88	(I)
	200	22,000	79	14.17	5.96	3.67	
	250	29,000	102	15.29	7.03	4.74	
HADCO Capitol Acorn, HPS	100	9,500	43	15.60	4.63	2.00	
	150	16,000	62	16.42	5.55	2.88	
	200	22,000	79	17.19	6.33	3.67	
	250	29,000	102	18.28	7.41	4.74	
Special Architectural Types							
HADCO Independence, HPS	100	9,500	43	11.88	4.15	2.00	
	150	16,000	62	12.47	5.01	2.88	
HADCO Techtra, HPS	100	9,500	43	20.55	5.23	2.00	
	150	16,000	62	20.94	6.06	2.88	
	250	29,000	102	22.19	7.88	4.74	
HADCO Westbrooke, HPS	70	6,300	30	14.02	3.90	1.40	
	100	9,500	43	14.39	4.47	2.00	
	150	16,000	62	15.28	5.36	2.88	
	200	22,000	79	16.33	6.21	3.67	
	250	29,000	102	17.25	7.27	4.74	(R)(I)(I)

* Not offered.

SCHEDULE 491 (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	$ 8.44	$ 4.73	$ 2.79	(I)(I)(I)
Flood, Metal Halide	350	30,000	139	14.25	8.68	6.46	
Flood, HPS	750	105,000	285	22.65	15.96	13.25	(I)
Holophane Mongoose, HPS	150	16,000	62	13.11	5.10	2.88	(R)
	250	29,000	102	14.32	6.90	4.74	(R)(I)
Option C Only **							
Ornamental Acorn Twin	85	9,600	64	*	*	2.98	
Ornamental Acorn	55	2,800	21	*	*	0.98	
Ornamental Acorn Twin	55	5,600	42	*	*	1.95	
Composite, Twin	140	6,815	54	*	*	2.51	
	175	9,815	66	*	*	3.07	

(I)

RATES FOR CUSTOM POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Aluminum, Regular	16	$ 8.39	$0.19	(R)(I)
	25	13.93	0.31	
	30	15.05	0.34	(I)
	35	18.00	0.40	
Aluminum Davit	25	13.90	0.31	
	30	13.83	0.31	(I)
	35	15.12	0.34	
	40	20.52	0.46	
Aluminum Double Davit	30	20.42	0.46	
Aluminum, HADCO, Fluted Victorian Ornamental	14	12.29	0.28	(R)(I)

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

SCHEDULE 491 (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	$24.18	$0.54	(R)(I)
Aluminum, HADCO, Fluted Ornamental	16	12.56	0.28	
Aluminum, HADCO, Non-Fluted Ornamental Westbrooke	16	25.69	0.58	(I)
Aluminum, HADCO, Fluted Westbrooke	18	24.24	0.54	
Aluminum, HADCO, Non-Fluted, Westbrooke	18	25.69	0.58	
Aluminum, Painted Ornamental	35	41.28	0.92	
Concrete, Decorative Ameron	20	24.12	0.54	
Concrete, Ameron Post-Top	25	24.12	0.54	(I)
Fiberglass, HADCO, Fluted Ornamental Black	14	14.86	0.33	
Fiberglass, Smooth	18	6.16	0.14	
Fiberglass, Regular,				
color may vary	22	5.51	0.12	
color may vary	35	9.04	0.20	
Fiberglass, Anchor Base, Gray	35	16.51	0.37	(I)
Fiberglass, Direct Bury with Shroud	18	9.96	0.22	(R)

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	Option C	
Cobrahead, Mercury Vapor	100	4,000	39	*	*	$ 1.81	(I)(I)(I)
	175	7,000	66	$ 8.01	$ 4.62	3.07	
	250	10,000	94	*	*	4.37	
	400	21,000	147	12.60	8.52	6.84	
	1,000	55,000	374	23.81	19.40	17.39	(I)(I)(I)

* Not offered.

SCHEDULE 491 (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	$ 7.89	$ 3.10	$ 1.40	(R)(I)(I)
Mercury Vapor	175	7,000	66	9.51	4.72	3.07	(I) (I)
Special box, Anodized Aluminum							
Similar to GardCo Hub							
HPS	Twin 70	6,300	60	*	*	2.79	
	70	6,300	30	*	*	1.40	
	100	9,500	43	*	4.06	2.00	
	150	16,000	62	*	4.96	2.88	(I)
	250	29,000	102	*	*	4.74	(I)
	400	50,000	163	*	*	7.58	
Metal Halide	250	20,500	99	*	5.88	4.60	(I)
	400	40,000	156	*	8.53	7.25	
Cobrahead, Metal Halide	175	12,000	71	9.18	5.07	3.30	(I)
Flood, Metal Halide	400	40,000	156	13.92	9.06	7.25	(I)
Cobrahead, Dual Wattage HPS							
70/100 Watt Ballast	100	9,500	43	*	3.61	2.00	
100/150 Watt Ballast	100	9,500	43	*	3.61	2.00	
100/150 Watt Ballast	150	16,000	62	*	4.51	2.88	
Special Architectural Types							
KIM SBC Shoebox, HPS	150	16,000	62	*	5.52	2.88	
KIM Archetype, HPS	250	29,000	102	*	7.61	4.74	
	400	50,000	163	*	9.85	7.58	(I)(I)

* Not offered

SCHEDULE 491 (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	$ 11.25	$ 3.54	$ 1.40	(R)(I)(I)
Special GardCo Bronze Alloy							
HPS	70	5,000	30	*	*	1.40	
Mercury Vapor	175	7,000	66	*	*	3.07	
Special Acrylic Sphere							
Mercury Vapor	400	21,000	147	*	*	6.84	
Early American Post-Top, HPS							
Black	70	6,300	30	7.04	2.98	1.40	(R)(I)
Rectangle Type	200	22,000	79	*	*	3.67	
Incandescent	92	1,000	31	*	*	1.44	
	182	2,500	62	*	*	2.88	
Town and Country Post-Top							
Mercury Vapor	175	7,000	66	8.72	4.66	3.07	(I)(I)
Flood, HPS	70	6,300	30	6.27	2.88	1.40	(R)(R)
	100	9,500	43	7.03	3.60	2.00	
	200	22,000	79	10.12	5.42	3.67	(I)(I)
Cobrahead, HPS							
Power Door	310	37,000	124	11.90	7.85	5.77	(I)(I)
Special Types Customer-Owned & Maintained							
Ornamental, HPS	100	9,500	43	*	*	2.00	
Twin ornamental, HPS	Twin 100	9,500	86	*	*	4.00	
Compact Fluorescent	28	N/A	12	*	*	0.56	

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* Not offered.

SCHEDULE 491 (Continued)

RATES FOR OBSOLETE LIGHTING POLES

Type of Pole	Poles Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Aluminum Post	30	$ 8.39	*	(R)
Bronze Alloy GardCo	12	*	$0.17	
Concrete, Ornamental	35 or less	13.93	0.31	(R)
Steel, Painted Regular **	25	13.93	0.31	
Steel, Painted Regular **	30	15.05	0.34	(R)(I)
Steel, Unpainted 6-foot Mast Arm **	30	*	0.31	
Steel, Unpainted 6-foot Davit Arm **	30	*	0.31	
Steel, Unpainted 8-foot Mast Arm **	35	*	0.34	
Steel, Unpainted 8-foot Davit Arm **	35	*	0.34	(I)
Wood, Laminated without Mast Arm	20	6.18	0.14	(R)
Wood, Laminated Street Light Only	20	6.18	*	
Wood, Curved Laminated	30	9.74	0.22	(I)
Wood, Painted Underground	35	7.03	0.16	(I)
Wood, Painted Street Light Only	35	7.03	*	(R)

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

SERVICE RATES FOR ALTERNATIVE LIGHTING

The purpose of this series of luminaires is to provide lighting utilizing the latest in technological advances in lighting equipment. The Company does not maintain an inventory of this equipment, and so delays with maintenance are likely. This equipment is more subject to obsolescence since it is experimental and yet to be determined reliable or cost effective. The Company will order and replace the equipment subject to availability.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	Monthly Rates Option C	
Special Architectural Types Including Philips QL Induction Lamp Systems							
HADCO Victorian, QL	85	6,000	32	*	$ 2.26	$ 1.49	(I)(I)
	165	12,000	60	*	3.83	2.79	
	165	12,000	60	$24.65	4.02	2.79	(R)(I)(I)

SCHEDULE 492
TRAFFIC SIGNALS
COST OF SERVICE OPT-OUT

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 500 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. Service under this schedule is limited to the first 300 MWa that applies to Schedules 485, 489, 490, 491, 492, and 495

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	1.973 ¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.

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 492 (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 Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-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 $1.777 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.

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.

LOSSES

The following adjustment factors will be used where losses are to be included in the energy charges:

Secondary Delivery Voltage 1.0685 **(R)**

ADJUSTMENTS

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

SCHEDULE 495 (Continued)

STREETLIGHT POLES SERVICE OPTIONS

Option A – Poles

See Schedule 91/491/591 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 4.650 ¢ per kWh **(I)**

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.

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 Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-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.

SCHEDULE 495 (Continued)

MARKET BASED PRICING OPTION (Continued)

Wheeling Charge

The Wheeling Charge will be $1.777 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.

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.

LOSSES

The following adjustment factors will be used where losses are to be included in the energy charges:

(R)

Secondary Delivery Voltage	1.0685

SCHEDULE 495 (Continued)

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rates [1]	Straight Time	Overtime
	$122.00 per hour	$163.00 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	$3.96	(R)
LED	50	3,162	17	4.15	
LED	52	3,757	18	4.59	
LED	67	5,050	23	5.25	
LED	106	7,444	36	6.66	(R)

SCHEDULE 495 (Continued)

RATES FOR DECORATIVE LIGHTING

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

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rate Option A	
Acorn	60	5,488	21	$13.17	(R)
	70	4,332	24	15.19	
Westbrooke (Non-Flared)	49	5,094	17	17.76	
	69	6,680	24	18.86	
	109	8,176	37	19.73	
	136	12,728	46	23.80	
	206	18,159	70	24.92	
Westbrooke (Flared)	49	5,094	17	19.88	
	69	6,680	24	20.56	
	109	8,176	37	21.82	
	136	12,728	46	25.11	
	206	18,159	70	26.23	(R)

SPECIALTY SERVICES OFFERED

Upon Customer request and subject to the Company's operating constraints, 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.

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.

ADJUSTMENTS

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

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	$ 9.09 [(2)]	(I)
	400	21,000	147	13.25 [(2)]	|
	1,000	55,000	374	24.46 [(2)]	(I)
HPS	70	6,300	30	7.53 [(2)]	(R)
	100	9,500	43	8.07	(R)
	150	16,000	62	8.98	(I)
	200	22,000	79	10.08	|
	250	29,000	102	11.12	|
	310	37,000	124	12.55 [(2)]	|
	400	50,000	163	14.37	(I)
Flood , HPS	100	9,500	43	8.11 [(2)]	(R)
	200	22,000	79	10.77 [(2)]	(I)
	250	29,000	102	11.86	|
	400	50,000	163	14.70	(I)
Shoebox, HPS (bronze color, flat lens, or drop lens, multi-volt)	70	6,300	30	8.88	(R)
	100	9,500	43	9.67	|
	150	16,500	62	10.81	(R)

(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	$12.53	(R)
HADCO Victorian, HPS	150	16,500	62	13.31	
	200	22,000	79	14.82	
	250	29,000	102	15.94	
Early American Post-Top, HPS, Black	100	9,500	43	8.83	(R)
Special Types					
Cobrahead, Metal Halide	150	10,000	60	9.52	(I)
Cobrahead, Metal Halide	175	12,000	71	10.26	
Flood, Metal Halide	350	30,000	139	14.90	
Flood, Metal Halide	400	40,000	156	14.57	
Flood, HPS	750	105,000	285	23.30	(I)
HADCO Independence, HPS	100	9,500	43	12.53	(R)
	150	16,000	62	13.12	
HADCO Capitol Acorn, HPS	100	9,500	43	16.25	
	150	16,000	62	17.07	
	200	22,000	79	17.84	
	250	29,000	102	18.93	
HADCO Techtra, HPS	100	9,500	43	21.20	
	150	16,000	62	21.59	
	250	29,000	102	22.84	
HADCO Westbrooke, HPS	70	6,300	30	14.67	
	100	9,500	43	15.04	
	150	16,000	62	15.93	
	200	22,000	79	16.98	
	250	29,000	102	17.90	
KIM Archetype, HPS	250	29,000	102	20.73	(R)
	400	50,000	163	18.74	
Holophane Mongoose, HPS	150	16,000	62	13.76	(R)
	250	29,000	102	14.97	(R)

(1) See Schedule 100 for applicable adjustments.

SCHEDULE 515 (Continued)

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

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate[1] Per Luminaire	
Acorn					
LED	60	5,488	21	$13.62	(R)
	70	4,332	24	15.60	
Cobrahead					
LED	37	2,530	13	4.37	
	50	3,162	17	4.56	
	52	3,757	18	5.00	
	67	5,050	23	5.50	
	106	7,444	36	6.92	
Westbrooke LED (Non-Flare)	49	5,094	17	18.10	
	69	6,680	24	19.18	
	109	8,176	37	20.04	
	136	12,728	46	24.03	
	206	18,159	70	25.15	
Westbrooke LED (Flare)	49	5,094	17	20.17	
	69	6,680	24	20.84	
	109	8,176	37	22.09	
	136	12,728	46	25.31	
	206	18,159	70	26.43	(R)
CREE XSP LED	25	2529	9	3.23	(I)
	42	3819	14	3.56	(I)
	48	4373	16	4.12	
	56	5863	19	4.77	(R)
	91	8747	31	5.33	(I)

(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	$ 7.03	(R)
	40 to 55	9.20	
Wood, Painted Underground	35 or less	7.03 [2]	
Wood, Curved laminated	30 or less	8.71 [2]	
Aluminum, Regular	16	8.39	
	25	13.93	
	30	15.05	
	35	18.00	
Aluminum, Fluted Ornamental	14	12.29	
Aluminum Davit	25	12.88	
	30	13.83	
	35	15.12	
	40	20.52	
Aluminum Double Davit	30	20.42	
Aluminum, HADCO, Fluted Ornamental	16	12.56	
Aluminum, HADCO, Non-fluted	18	24.18	
Concrete, Ameron Post-Top	25	24.12	
Fiberglass Fluted Ornamental; Black	14	14.86	
Fiberglass, Regular			
Black,	20	6.18	
Gray or Bronze;	30	10.50	
Other Colors (as available)	35	9.04	
Fiberglass, Anchor Base Gray	35	16.51	
Fiberglass, Direct Bury with Shroud	18	9.96	(R)

(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	$15.00	(I)
Three Phase	$20.00	
Distribution Charge		
First 5,000 kWh	3.829 ¢ per kWh	
Over 5,000 kWh	0.873 ¢ per kWh	(I)

* 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, 2015. **(C)**

MONTHLY RATE

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

Basic Charge		
Single Phase Service	$25.00	
Three Phase Service	$25.00	
Distribution Charge	6.503 ¢ 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.

Portland General Electric Company — **Sixth Revision of Sheet No. 549-1**
P.U.C. Oregon No. E-18 — **Canceling Fifth Revision of Sheet No. 549-1**

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**	$40.00	**(I)**
Winter Months**	No Charge	
Distribution Charge		
First 50 kWh per kW of Demand	5.964 ¢ per kWh	**(I)**
Over 50 kWh per kW of Demand	3.964 ¢ 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	$5,440.00	$4,870.00	$5,600.00	(I)
Distribution Charge				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.97	$1.94	$1.94	
Over 4,000 kW	$1.50	$1.47	$1.47	
per kW of monthly On-Peak Demand**	$2.24	$2.20	$0.83	(I)(R)
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	(0.036) ¢	(0.036) ¢	(0.037) ¢	(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**	$0.087	$0.086	$0.032	**(I)(R)**
Transaction Fee				**(D)**
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 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 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	
Three Phase Service	$40.00	
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 30 kW	$2.96	(I)
Over 30 kW	$2.86	
per kW of monthly On-Peak Demand	$2.24	(I)
System Usage Charge		
per kWh	0.518 ¢	(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 585
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE
(201 – 4,000 kW)

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 13 months, or with seven months or less of service has not had a Demand exceeding 4,000 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)*:

	Delivery Voltage		
	Secondary	Primary	
Basic Charge	$470.00	$500.00	(R)
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 200 kW	$3.09	$3.04	(I)
Over 200 kW	$2.19	$2.14	|
per kW of monthly On-Peak Demand	$2.24	$2.20	(I)
System Usage Charge			
per kWh	(0.016) ¢	(0.017) ¢	(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)

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.

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	$5,440.00	$4,870.00	$5,600.00	**(I)**
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.97	$1.94	$1.94	
Over 4,000 kW	$1.50	$1.47	$1.47	
per kW of monthly on-peak Demand	$2.24	$2.20	$0.83	**(I)(R)**
System Usage Charge				
per kWh	(0.036) ¢	(0.036) ¢	(0.037) ¢	**(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 590
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE
(>4,000 kW and Aggregate to >100 MWa)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer who meet the following conditions: 1) Individual account 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 2) where combined usage of all accounts meeting condition 1 for the Large Nonresidential Customer aggregate to at least 100 MWa in a calendar year; and 3) the customer maintains a load factor of 80% or greater for each account; and 4) who has chosen to receive Electricity from an 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)*: (C)

Basic Charge	$25,000.00	(I)
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 4,000 kW	$1.08	(R)
Over 4,000 kW	$1.08	(R)
per kW of monthly on-peak Demand	$2.20	(I)
System Usage Charge		
per kWh	(0.044) ¢	(R)(C)

* 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 590 (Concluded)

SPECIAL CONDITIONS

(D)

1. A Customer is required to have interval metering and meter communications in place prior to initiation of service under this schedule. (T)

2. If the Customer is served at either primary or subtransmission voltage, the Customer will provide, install, and maintain on the Customer's premises all necessary transformers to which the Company's service is directly or indirectly connected. The Customer also will provide, install, and maintain the necessary switches, cutouts, protection equipment, and in addition, the necessary wiring on both sides of the transformers. All transformers, equipment, and wiring will be of types and characteristics approved by the Company, and the arrangement and operation of such equipment will be subject to the approval of the Company. (T)

TERM

Service will be for not less than one year or as otherwise provided under this schedule.

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	4.650 ¢ 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

Portland General Electric Company — **Eleventh Revision of Sheet No. 591-7**
P.U.C. Oregon No. E-18 — **Canceling Tenth Revision of Sheet No. 591-7**

SCHEDULE 591 (Continued)

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rates [(1)]	Straight Time	Overtime
	$122.00 per hour	$163.00 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	Monthly Rates Option B	Monthly Rates Option C	
Cobrahead Power Doors **							
	70	6,300	30	*	$ 2.76	$ 1.40	(I)(I)
	100	9,500	43	*	3.38	2.00	
	150	16,000	62	*	4.26	2.88	
	200	22,000	79	*	5.11	3.67	
	250	29,000	102	*	6.20	4.74	
	400	50,000	163	*	9.05	7.58	
Cobrahead, Non-Power Door	70	6.300	30	$ 6.45	3.01	1.40	(R) (I)
	100	9,500	43	6.99	3.60	2.00	
	150	16,000	62	7.90	4.49	2.88	
	200	22,000	79	9.43	5.35	3.67	
	250	29,000	102	10.47	6.42	4.74	
	400	50,000	163	13.72	9.31	7.58	
Flood	250	29,000	102	11.21	6.51	4.74	
	400	50,000	163	14.05	9.35	7.58	(I)
Early American Post-Top	100	9,500	43	7.75	3.69	2.00	(R)
Shoebox (Bronze color, flat Lens, or drop lens, multi-volt)	70	6,300	30	7.80	3.18	1.40	
	100	9,500	43	8.59	3.80	2.00	(R)(I)(I)
	150	16,000	62	9.73	4.72	2.88	

* 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	$ 6.18	$0.14	(R)
Fiberglass, Bronze	30	9.74	0.22	(I)
Fiberglass, Gray	30	10.50	0.24	
Wood, Standard	30 to 35	7.03	0.16	
Wood, Standard	40 to 55	9.20	0.21	(R)(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	$11.88	$ 4.17	$ 2.00	(R)(I)(I)
HADCO Victorian, HPS	150	16,000	62	12.66	5.05	2.88	
	200	22,000	79	14.17	5.96	3.67	
	250	29,000	102	15.29	7.03	4.74	
HADCO Capitol Acorn, HPS	100	9,500	43	15.60	4.63	2.00	
	150	16,000	62	16.42	5.55	2.88	
	200	22,000	79	17.19	6.33	3.67	
	250	29,000	102	18.28	7.41	4.74	
Special Architectural Types							
HADCO Independence, HPS	100	9,500	43	11.88	4.15	2.00	
	150	16,000	62	12.47	5.01	2.88	
HADCO Techtra, HPS	100	9,500	43	20.55	5.23	2.00	
	150	16,000	62	20.94	6.06	2.88	
	250	29,000	102	22.19	7.88	4.74	
HADCO Westbrooke, HPS	70	6,300	30	14.02	3.90	1.40	
	100	9,500	43	14.39	4.47	2.00	
	150	16,000	62	15.28	5.36	2.88	
	200	22,000	79	16.33	6.21	3.67	
	250	29,000	102	17.25	7.27	4.74	(R)(I)(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	$ 8.44	$ 4.73	$ 2.79	(I)(I)(I)
Flood, Metal Halide	350	30,000	139	14.25	8.68	6.46	
Flood, HPS	750	105,000	285	22.65	15.96	13.25	
Holophane Mongoose, HPS	150	16,000	62	13.11	5.10	2.88	(I) (R)
	250	29,000	102	14.32	6.90	4.74	(R)(I)
Option C Only **							
Ornamental Acorn Twin	85	9,600	64	*	*	2.98	
Ornamental Acorn	55	2,800	21	*	*	0.98	
Ornamental Acorn Twin	55	5,600	42	*	*	1.95	
Composite, Twin	140	6,815	54	*	*	2.51	
	175	9,815	66	*	*	3.07	(I)

RATES FOR CUSTOM POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Aluminum, Regular	16	$ 8.39	$0.19	(R)(I)
	25	13.93	0.31	
	30	15.05	0.34	(I)
	35	18.00	0.40	
Aluminum Davit	25	13.90	0.31	
	30	13.83	0.31	(I)
	35	15.12	0.34	
	40	20.52	0.46	
Aluminum Double Davit	30	20.42	0.46	
Aluminum, HADCO, Fluted Victorian Ornamental	14	12.29	0.28	(R)(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	$24.18	$0.54	(R)(I)
Aluminum, HADCO, Fluted Ornamental	16	12.56	0.28	
Aluminum, HADCO, Non-Fluted Ornamental Westbrooke	16	25.69	0.58	(I)
Aluminum, HADCO, Fluted Westbrooke	18	24.24	0.54	
Aluminum, HADCO, Non-Fluted, Westbrooke	18	25.69	0.58	
Aluminum, Painted Ornamental	35	41.28	0.92	
Concrete, Decorative Ameron	20	24.12	0.54	
Concrete, Ameron Post-Top	25	24.12	0.54	(I)
Fiberglass, HADCO, Fluted Ornamental Black	14	14.86	0.33	
Fiberglass, Smooth	18	6.16	0.14	
Fiberglass, Regular,				
color may vary	22	5.51	0.12	
color may vary	35	9.04	0.20	
Fiberglass, Anchor Base, Gray	35	16.51	0.37	(I)
Fiberglass, Direct Bury with Shroud	18	9.96	0.22	(R)

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	Option C	
Cobrahead, Mercury Vapor	100	4,000	39	*	*	$ 1.81	(I)
	175	7,000	66	$ 8.01	$ 4.62	3.07	(I)(I)
	250	10,000	94	*	*	4.37	
	400	21,000	147	12.60	8.52	6.84	(I)(I)
	1,000	55,000	374	23.81	19.40	17.39	(I)(I)(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	$ 7.89	$ 3.10	$ 1.40	(R)(I)(I)
Mercury Vapor	175	7,000	66	9.51	4.72	3.07	(I)(I)(I)
Special box, Anodized Aluminum							
Similar to GardCo Hub							
HPS	Twin 70	6,300	60	*	*	2.79	
	70	6,300	30	*	*	1.40	
	100	9,500	43	*	4.06	2.00	(I)
	150	16,000	62	*	4.96	2.88	(I)
	250	29,000	102	*	*	4.74	
	400	50,000	163	*	*	7.58	
Metal Halide	250	20,500	99	*	5.88	4.60	(I)
	400	40,000	156	*	8.53	7.25	
Cobrahead, Metal Halide	175	12,000	71	9.18	5.07	3.30	(I)
Flood, Metal Halide	400	40,000	156	13.92	9.06	7.25	(I)
Cobrahead, Dual Wattage HPS							
70/100 Watt Ballast	100	9,500	43	*	3.61	2.00	
100/150 Watt Ballast	100	9,500	43	*	3.61	2.00	
100/150 Watt Ballast	150	16,000	62	*	4.51	2.88	
Special Architectural Types Including Philips QL Induction Lamp Systems							
HADCO Victorian, QL	85	6,000	32	*	$ 2.26	$ 1.49	
	165	12,000	60	*	3.83	2.79	
	165	12,000	60	$24.65	4.02	2.79	(R)
Special Architectural Types							
KIM SBC Shoebox, HPS	150	16,000	62	*	5.52	2.88	
KIM Archetype, HPS	250	29,000	102	*	7.61	4.74	
	400	50,000	163	*	9.85	7.58	(I)(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	$ 11.25	$ 3.54	$ 1.40	(R)(I)(I)
Special GardCo Bronze Alloy							
HPS	70	5,000	30	*	*	1.40	
Mercury Vapor	175	7,000	66	*	*	3.07	
Special Acrylic Sphere							
Mercury Vapor	400	21,000	147	*	*	6.84	
Early American Post-Top, HPS							
Black	70	6,300	30	7.04	2.98	1.40	(R)(I)
Rectangle Type	200	22,000	79	*	*	3.67	
Incandescent	92	1,000	31	*	*	1.44	
	182	2,500	62	*	*	2.88	
Town and Country Post-Top							
Mercury Vapor	175	7,000	66	8.72	4.66	3.07	(I)(I)
Flood, HPS	70	6,300	30	6.27	2.88	1.40	(R)(R)
	100	9,500	43	7.03	3.60	2.00	(I)(I)
	200	22,000	79	10.12	5.42	3.67	
Cobrahead, HPS							
Power Door	310	37,000	124	11.90	7.85	5.77	(I)(I)
Special Types Customer-Owned & Maintained							
Ornamental, HPS	100	9,500	43	*	*	2.00	
Twin ornamental, HPS	Twin 100	9,500	86	*	*	4.00	
Compact Fluorescent	28	N/A	12	*	*	0.56	(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	$ 8.39	*	(R)
Bronze Alloy GardCo	12	*	$0.17	
Concrete, Ornamental	35 or less	13.93	0.31	(R)
Steel, Painted Regular **	25	13.93	0.31	
Steel, Painted Regular **	30	15.05	0.34	(R)(I)
Steel, Unpainted 6-foot Mast Arm **	30	*	0.31	
Steel, Unpainted 6-foot Davit Arm **	30	*	0.31	
Steel, Unpainted 8-foot Mast Arm **	35	*	0.34	
Steel, Unpainted 8-foot Davit Arm **	35	*	0.34	(I)
Wood, Laminated without Mast Arm	20	6.18	0.14	(R)
Wood, Laminated Street Light Only	20	6.18	*	
Wood, Curved Laminated	30	9.74	0.22	(I)
Wood, Painted Underground	35	7.03	0.16	(I)
Wood, Painted Street Light Only	35	7.03	*	(R)

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

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	1.973 ¢ per kWh	**(I)**

* 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 (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 4.650 ¢ per kWh (I)

Energy Charge Provided by Energy Service Supplier

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rates (1)	Straight Time	Overtime
	$122.00 per hour	$163.00 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	$3.96	(R)
LED	50	3,162	17	4.15	
LED	52	3,757	18	4.59	
LED	67	5,050	23	5.25	
LED	106	7,444	36	6.66	(R)

SCHEDULE 595 (Continued)

RATES FOR DECORATIVE LIGHTING

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

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rate Option A	
Acorn	60	5,488	21	$13.17	(R)
	70	4,332	24	15.19	
Westbrooke (Non-Flared)	49	5,094	17	17.76	
	69	6,680	24	18.86	
	109	8,176	37	19.73	
	136	12,728	46	23.80	
	206	18,159	70	24.92	
Westbrooke (Flared)	49	5,094	17	19.88	
	69	6,680	24	20.56	
	109	8,176	37	21.82	
	136	12,728	46	25.11	
	206	18,159	70	26.23	(R)

SPECIALTY SERVICES OFFERED

Upon Customer request and subject to the Company's operating constraints, 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.

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 600 (Concluded)

SPECIAL CONDITION

The ESS must purchase firm Transmission Service under the Company's OATT for not less than one-month duration and will be charged at the OATT monthly rate for firm transmission.

PGE SYSTEM LOSSES

The ESS will schedule sufficient Energy to provide for the following losses on the Company's system:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Losses:	4.74%	2.85%	1.45%	**(R)(I)**

SCHEDULE 750
INFORMATIONAL ONLY: FRANCHISE FEE RATE RECOVERY

PURPOSE

To inform customers regarding the level of franchise fee rate recovery contained in each schedule's system usage or distribution charges.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all Residential and Nonresidential Customers located within the Company's service territory.

FRANCHISE FEE RATE RECOVERY

The Rates, included in the applicable system usage and distribution charges are:

Schedule	Franchise Fee Rate		Included in:
7	0.293	¢ per kWh	Distribution Charge
15	0.584	¢ per kWh	Distribution Charge
32	0.269	¢ per kWh	Distribution Charge
38	0.326	¢ per kWh	Distribution Charge
47	0.691	¢ per kWh	Distribution Charge
49	0.570	¢ per kWh	Distribution Charge
75			
Secondary	0.161	¢ per kWh	System Usage Charge
Primary	0.158	¢ per kWh	System Usage Charge
Subtransmission	0.156	¢ per kWh	System Usage Charge
76R			
Secondary	0.000	¢ per kWh	System Usage Charge
Primary	0.000	¢ per kWh	System Usage Charge
Subtransmission	0.000	¢ per kWh	System Usage Charge

DO NOT BILL

SCHEDULE 750 (Continued)

FRANCHISE FEE RATE RECOVERY (Continued)

The Rates, included in the applicable system usage and distribution charges are:

Schedule	Franchise Fee Rate		Included in:
83	0.215	¢ per kWh	System Usage Charge
85			
Secondary	0.189	¢ per kWh	System Usage Charge
Primary	0.185	¢ per kWh	System Usage Charge
89			
Secondary	0.161	¢ per kWh	System Usage Charge
Primary	0.158	¢ per kWh	System Usage Charge
Subtransmission	0.156	¢ per kWh	System Usage Charge
90	0.148	¢ per kWh	System Usage Charge
91	0.442	¢ per kWh	Distribution Charge
92	0.185	¢ per kWh	Distribution Charge
95	0.442	¢ per kWh	Distribution Charge
485			
Secondary	0.059	¢ per kWh	System Usage Charge
Primary	0.058	¢ per kWh	System Usage Charge
489			
Secondary	0.040	¢ per kWh	System Usage Charge
Primary	0.040	¢ per kWh	System Usage Charge
Subtransmission	0.039	¢ per kWh	System Usage Charge
490	0.033	¢ per kWh	System Usage Charge
491	0.311	¢ per kWh	Distribution Charge
492	0.048	¢ per kWh	Distribution Charge
495	0.311	¢ per kWh	Distribution Charge

DO NOT BILL

SCHEDULE 750 (Concluded)

FRANCHISE FEE RATE RECOVERY (Concluded)

The Rates, included in the applicable system usage and distribution charges are:

Schedule	Franchise Fee Rate		Included in:
515	0.453	¢ per kWh	Distribution Charge
532	0.115	¢ per kWh	Distribution Charge
538	0.172	¢ per kWh	Distribution Charge
549	0.387	¢ per kWh	Distribution Charge
575			
Secondary	0.040	¢ per kWh	System Usage Charge
Primary	0.040	¢ per kWh	System Usage Charge
Subtransmission	0.039	¢ per kWh	System Usage Charge
576R			
Secondary	0.000	¢ per kWh	System Usage Charge
Primary	0.000	¢ per kWh	System Usage Charge
Subtransmission	0.000	¢ per kWh	System Usage Charge
583	0.061	¢ per kWh	System Usage Charge
585			
Secondary	0.059	¢ per kWh	System Usage Charge
Primary	0.058	¢ per kWh	System Usage Charge
590	0.033	¢ per kWh	System Usage Charge
591	0.311	¢ per kWh	Distribution Charge
592	0.048	¢ per kWh	Distribution Charge
595	0.311	¢ per kWh	Distribution Charge

DO NOT BILL

TABLE 1
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS
2015

		Forecast SDEC13E15		TOTAL ELECTRIC BILLS			
				CURRENT	PROPOSED	Change	
CATEGORY	**RATE SCHEDULE**	CUSTOMERS	MWH SALES	w/ Sch. 122a, 125	w/ Sch. 122a, 125	AMOUNT	PCT.
Residential	7	740,049	7,462,740	$868,513,187	$883,528,411	$15,015,225	1.7%
Employee Discount				($928,911)	($943,359)	($14,448)	
Subtotal				$867,584,276	$882,585,053	$15,000,777	1.7%
Outdoor Area Lighting	15	0	15,972	$3,611,672	$3,581,844	($29,828)	-0.8%
General Service <30 kW	32	89,471	1,556,500	$167,876,564	$168,928,465	$1,051,901	0.6%
Opt. Time-of-Day G.S. >30 kW	38	561	43,599	$5,535,939	$5,735,186	$199,247	3.6%
Irrig. & Drain. Pump. < 30 kW	47	2,991	18,147	$2,918,195	$3,268,524	$350,329	12.0%
Irrig. & Drain. Pump. > 30 kW	49	1,329	69,025	$7,641,200	$8,557,692	$916,492	12.0%
General Service 31-200 kW	83	10,953	2,735,660	$237,384,969	$237,229,168	($155,801)	-0.1%
General Service 201-4,000 kW							
Secondary	85-S	1,239	2,431,372	$187,001,824	$185,954,979	($1,046,846)	-0.6%
Primary	85-P	192	645,752	$46,497,902	$46,783,219	$285,317	0.6%
Schedule 89 > 4 MW							
Primary	89-P	18	913,928	$57,219,064	$57,262,768	$43,704	0.1%
Subtransmission	89-T	5	209,810	$14,001,886	$13,946,816	($55,070)	-0.4%
Schedule 90	90-P	4	1,453,535	$86,272,878	$84,934,963	($1,337,916)	-1.6%
Street & Highway Lighting	91/95	205	97,094	$17,402,841	$17,430,166	$27,325	0.2%
Traffic Signals	92	17	3,327	$251,189	$248,826	($2,362)	-0.9%
COS TOTALS		847,034	17,656,462	$1,701,200,398	$1,716,447,667	$15,247,269	0.9%
Direct Access Service 201-4,000 kW							
Secondary	485-S	160	436,001	$10,089,364	$9,156,620	($932,744)	
Primary	485-P	41	220,953	$5,140,516	$4,724,977	($415,539)	
Direct Access Service > 4 MW							
Secondary	489-S	1	14,864	$510,479	$498,879	($11,599)	
Primary	489-P	9	506,343	$7,432,529	$6,836,735	($595,794)	
Subtransmission	489-T	3	333,091	$3,890,552	$3,341,898	($548,654)	
DIRECT ACCESS TOTALS		214	1,511,253	$27,063,440	$24,559,110	($2,504,330)	
COS AND DA CYCLE TOTALS		847,248	19,167,715	$1,728,263,838	$1,741,006,777	$12,742,939	0.7%

TABLE 2
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS
2015

CATEGORY	RATE SCHEDULE	Forecast SDEC13E15 CUSTOMERS	MWH SALES	TOTAL ELECTRIC BILLS CURRENT w/ Sch. 122a, 125, 102	TOTAL ELECTRIC BILLS PROPOSED w/ Sch. 122a, 125, 102	Change AMOUNT	Change PCT.
Residential	7	740,049	7,462,740	$819,846,442	$828,762,922	$8,916,481	1.1%
Employee Discount				($881,711)	($890,244)	($8,533)	
Subtotal				$818,964,731	$827,872,679	$8,907,948	1.1%
Outdoor Area Lighting	15	0	15,972	$3,587,722	$3,554,871	($32,851)	-0.9%
General Service <30 kW	32	89,471	1,556,500	$166,368,971	$167,230,626	$861,655	0.5%
Opt. Time-of-Day G.S. >30 kW	38	561	43,599	$5,530,136	$5,728,650	$198,514	3.6%
Irrig. & Drain. Pump. < 30 kW	47	2,991	18,147	$2,810,615	$3,147,369	$336,754	12.0%
Irrig. & Drain. Pump. > 30 kW	49	1,329	69,025	$7,258,138	$8,126,291	$868,153	12.0%
General Service 31-200 kW	83	10,953	2,735,660	$235,890,529	$235,546,142	($344,387)	-0.1%
General Service 201-4,000 kW							
Secondary	85-S	1,239	2,431,372	$186,669,364	$185,580,564	($1,088,799)	-0.6%
Primary	85-P	192	645,752	$46,450,032	$46,729,308	$279,276	0.6%
Schedule 89 > 4 MW							
Primary	89-P	18	913,928	$57,219,064	$57,262,768	$43,704	0.1%
Subtransmission	89-T	5	209,810	$14,001,886	$13,946,816	($55,070)	-0.4%
Schedule 90	90-P	4	1,453,535	$86,272,878	$84,934,963	($1,337,916)	-1.6%
Street & Highway Lighting	91/95	205	97,094	$17,402,841	$17,430,166	$27,325	0.2%
Traffic Signals	92	17	3,327	$251,189	$248,826	($2,362)	-0.9%
COS TOTALS		847,034	17,656,462	$1,648,678,095	$1,657,340,038	$8,661,943	0.5%
Direct Access Service 201-4,000 kW							
Secondary	485-S	160	436,001	$10,089,364	$9,156,620	($932,744)	
Primary	485-P	41	220,953	$5,140,516	$4,724,977	($415,539)	
Direct Access Service > 4 MW							
Secondary	489-S	1	14,864	$510,479	$498,879	($11,599)	
Primary	489-P	9	506,343	$7,432,529	$6,836,735	($595,794)	
Subtransmission	489-T	3	333,091	$3,890,552	$3,341,898	($548,654)	
DIRECT ACCESS TOTALS		214	1,511,253	$27,063,440	$24,559,110	($2,504,330)	
COS AND DA CYCLE TOTALS		847,248	19,167,715	$1,675,741,535	$1,681,899,148	$6,157,613	0.4%

TABLE 3
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS
2015

CATEGORY	RATE SCHEDULE	Forecast SDEC13E15 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	740,049	7,462,740	$838,055,528	$837,494,329	($561,199)	-0.1%
Employee Discount				($901,500)	($899,733)	$1,767	
Subtotal				$837,154,028	$836,594,596	($559,432)	-0.1%
Outdoor Area Lighting	15	0	15,972	$3,624,713	$3,575,730	($48,982)	-1.4%
General Service <30 kW	32	89,471	1,556,500	$167,045,026	$166,070,010	($975,016)	-0.6%
Opt. Time-of-Day G.S. >30 kW	38	561	43,599	$5,622,989	$5,770,056	$147,068	2.6%
Irrig. & Drain. Pump. < 30 kW	47	2,991	18,147	$2,855,061	$3,165,138	$310,077	10.9%
Irrig. & Drain. Pump. > 30 kW	49	1,329	69,025	$7,414,795	$8,187,003	$772,208	10.4%
General Service 31-200 kW	83	10,953	2,735,660	$241,247,930	$237,675,464	($3,572,466)	-1.5%
General Service 201-4,000 kW							
Secondary	85-S	1,239	2,431,372	$191,161,747	$187,301,184	($3,860,563)	-2.0%
Primary	85-P	192	645,752	$47,582,131	$47,144,622	($437,509)	-0.9%
Schedule 89 > 4 MW							
Primary	89-P	18	913,928	$58,653,931	$57,728,871	($925,060)	-1.6%
Subtransmission	89-T	5	209,810	$14,329,190	$14,053,819	($275,371)	-1.9%
Schedule 90	90-P	4	1,453,535	$88,554,928	$85,719,871	($2,835,056)	-3.2%
Street & Highway Lighting	91/95	205	97,094	$17,616,448	$17,545,707	($70,740)	-0.4%
Traffic Signals	92	17	3,327	$257,044	$251,155	($5,889)	-2.3%
COS TOTALS		847,034	17,656,462	$1,683,119,959	$1,670,783,228	($12,336,732)	-0.7%
Direct Access Service 201-4,000 kW							
Secondary	485-S	160	436,001	$10,292,563	$8,862,778	($1,429,785)	
Primary	485-P	41	220,953	$5,238,447	$4,577,650	($660,797)	
Direct Access Service > 4 MW							
Secondary	489-S	1	14,864	$516,870	$489,069	($27,802)	
Primary	489-P	9	506,343	$7,589,496	$6,456,978	($1,132,518)	
Subtransmission	489-T	3	333,091	$3,993,810	$3,095,411	($898,399)	
DIRECT ACCESS TOTALS		214	1,511,253	$27,631,187	$23,481,886	($4,149,301)	
COS AND DA CYCLE TOTALS		847,248	19,167,715	$1,710,751,146	$1,694,265,113	($16,486,033)	-1.0%

TABLE 4
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS
2015

CATEGORY	RATE SCHEDULE	Forecast SDEC13E15 CUSTOMERS	MWH SALES	TOTAL ELECTRIC BILLS CURRENT with all supplementals except LIA & PPC	TOTAL ELECTRIC BILLS PROPOSED with all supplementals except LIA & PPC	Change AMOUNT	Change PCT.
Residential	7	740,049	7,462,740	$865,667,667	$865,106,468	($561,199)	-0.1%
Employee Discount				($901,500)	($899,733)	$1,767	
Subtotal				$864,766,167	$864,206,735	($559,432)	-0.1%
Outdoor Area Lighting	15	0	15,972	$3,720,554	$3,671,571	($48,982)	-1.3%
General Service <30 kW	32	89,471	1,556,500	$172,367,833	$171,392,817	($975,016)	-0.6%
Opt. Time-of-Day G.S. >30 kW	38	561	43,599	$5,796,145	$5,943,212	$147,068	2.5%
Irrig. & Drain. Pump. < 30 kW	47	2,991	18,147	$2,936,637	$3,246,715	$310,077	10.6%
Irrig. & Drain. Pump. > 30 kW	49	1,329	69,025	$7,634,170	$8,406,378	$772,208	10.1%
General Service 31-200 kW	83	10,953	2,735,660	$248,856,924	$245,284,458	($3,572,466)	-1.4%
General Service 201-4,000 kW							
Secondary	85-S	1,239	2,431,372	$196,724,916	$192,864,353	($3,860,563)	-2.0%
Primary	85-P	192	645,752	$48,174,223	$47,736,714	($437,509)	-0.9%
Schedule 89 > 4 MW							
Primary	89-P	18	913,928	$58,653,931	$57,728,871	($925,060)	-1.6%
Subtransmission	89-T	5	209,810	$14,329,190	$14,053,819	($275,371)	-1.9%
Schedule 90	90-P	4	1,453,535	$88,554,928	$85,719,871	($2,835,056)	-3.2%
Street & Highway Lighting	91/95	205	97,094	$18,143,668	$18,072,928	($70,740)	-0.4%
Traffic Signals	92	17	3,327	$265,561	$259,672	($5,889)	-2.2%
COS TOTALS		847,034	17,656,462	$1,730,924,847	$1,718,588,115	($12,336,732)	-0.7%
Direct Access Service 201-4,000 kW							
Secondary	485-S	160	436,001	$11,089,832	$9,660,047	($1,429,785)	
Primary	485-P	41	220,953	$5,535,287	$4,874,490	($660,797)	
Direct Access Service > 4 MW							
Secondary	489-S	1	14,864	$549,126	$521,325	($27,802)	
Primary	489-P	9	506,343	$7,589,496	$6,456,978	($1,132,518)	
Subtransmission	489-T	3	333,091	$3,993,810	$3,095,411	($898,399)	
DIRECT ACCESS TOTALS		214	1,511,253	$28,757,552	$24,608,250	($4,149,301)	
COS AND DA CYCLE TOTALS		847,248	19,167,715	$1,759,682,399	$1,743,196,366	($16,486,033)	-0.9%

TABLE 5
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS WITH PORT WESTWARD 2
2015

CATEGORY	RATE SCHEDULE	Forecast SDEC13E15 CUSTOMERS	MWH SALES	TOTAL ELECTRIC BILLS CURRENT with all supplementals except LIA & PPC	TOTAL ELECTRIC BILLS PROPOSED with all supplementals except LIA & PPC	Change AMOUNT	Change PCT.
Residential	7	740,049	7,462,740	$865,667,667	$888,240,962	$22,573,295	2.6%
Employee Discount				($901,500)	($924,875)	($23,375)	
Subtotal				$864,766,167	$887,316,088	$22,549,921	2.6%
Outdoor Area Lighting	15	0	15,972	$3,720,554	$3,710,862	($9,691)	-0.3%
General Service <30 kW	32	89,471	1,556,500	$172,367,833	$175,891,103	$3,523,270	2.0%
Opt. Time-of-Day G.S. >30 kW	38	561	43,599	$5,796,145	$6,069,213	$273,068	4.7%
Irrig. & Drain. Pump. < 30 kW	47	2,991	18,147	$2,936,637	$3,312,045	$375,407	12.8%
Irrig. & Drain. Pump. > 30 kW	49	1,329	69,025	$7,634,170	$8,641,754	$1,007,584	13.2%
General Service 31-200 kW	83	10,953	2,735,660	$248,856,924	$253,163,159	$4,306,235	1.7%
General Service 201-4,000 kW							
Secondary	85-S	1,239	2,431,372	$196,724,916	$199,672,194	$2,947,278	1.5%
Primary	85-P	192	645,752	$48,174,223	$49,499,619	$1,325,395	2.8%
Schedule 89 > 4 MW							
Primary	89-P	18	913,928	$58,653,931	$60,095,944	$1,442,013	2.5%
Subtransmission	89-T	5	209,810	$14,329,190	$14,588,834	$259,645	1.8%
Schedule 90	90-P	4	1,453,535	$88,554,928	$89,368,243	$813,315	0.9%
Street & Highway Lighting	91/95	205	97,094	$18,143,668	$18,311,779	$168,111	0.9%
Traffic Signals	92	17	3,327	$265,561	$268,256	$2,695	1.0%
COS TOTALS		847,034	17,656,462	$1,730,924,847	$1,769,909,094	$38,984,247	2.3%
Direct Access Service 201-4,000 kW							
Secondary	485-S	160	436,001	$11,089,832	$9,660,047	($1,429,785)	
Primary	485-P	41	220,953	$5,535,287	$4,874,490	($660,797)	
Direct Access Service > 4 MW							
Secondary	489-S	1	14,864	$549,126	$521,325	($27,802)	
Primary	489-P	9	506,343	$7,589,496	$6,456,978	($1,132,518)	
Subtransmission	489-T	3	333,091	$3,993,810	$3,095,411	($898,399)	
DIRECT ACCESS TOTALS		214	1,511,253	$28,757,552	$24,608,250	($4,149,301)	
COS AND DA CYCLE TOTALS		847,248	19,167,715	$1,759,682,399	$1,794,517,345	$34,834,946	2.0%

TABLE 6
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS WITH PORT WESTWARD 2 AND TUCANNON
2015

CATEGORY	RATE SCHEDULE	Forecast SDEC13E15 CUSTOMERS	MWH SALES	TOTAL ELECTRIC BILLS CURRENT with all supplementals except LIA & PPC	TOTAL ELECTRIC BILLS PROPOSED with all supplementals except LIA & PPC	Change AMOUNT	Change PCT.
Residential	7	740,049	7,462,740	$865,667,667	$909,285,890	$43,618,223	5.0%
Employee Discount				($901,500)	($947,746)	($46,245)	
Subtotal				$864,766,167	$908,338,144	$43,571,977	5.0%
Outdoor Area Lighting	15	0	15,972	$3,720,554	$3,746,640	$26,086	0.7%
General Service <30 kW	32	89,471	1,556,500	$172,367,833	$179,984,699	$7,616,866	4.4%
Opt. Time-of-Day G.S. >30 kW	38	561	43,599	$5,796,145	$6,183,442	$387,297	6.7%
Irrig. & Drain. Pump. < 30 kW	47	2,991	18,147	$2,936,637	$3,371,386	$434,749	14.8%
Irrig. & Drain. Pump. > 30 kW	49	1,329	69,025	$7,634,170	$8,855,043	$1,220,872	16.0%
General Service 31-200 kW	83	10,953	2,735,660	$248,856,924	$260,330,589	$11,473,665	4.6%
General Service 201-4,000 kW							
Secondary	85-S	1,239	2,431,372	$196,724,916	$205,847,878	$9,122,962	4.6%
Primary	85-P	192	645,752	$48,174,223	$51,101,085	$2,926,861	6.1%
Schedule 89 > 4 MW							
Primary	89-P	18	913,928	$58,653,931	$62,243,675	$3,589,744	6.1%
Subtransmission	89-T	5	209,810	$14,329,190	$15,075,593	$746,404	5.2%
Schedule 90	90-P	4	1,453,535	$88,554,928	$92,682,302	$4,127,374	4.7%
Street & Highway Lighting	91/95	205	97,094	$18,143,668	$18,529,270	$385,602	2.1%
Traffic Signals	92	17	3,327	$265,561	$276,041	$10,480	3.9%
COS TOTALS		847,034	17,656,462	$1,730,924,847	$1,816,565,787	$85,640,940	4.9%
Direct Access Service 201-4,000 kW							
Secondary	485-S	160	436,001	$11,089,832	$9,660,047	($1,429,785)	
Primary	485-P	41	220,953	$5,535,287	$4,874,490	($660,797)	
Direct Access Service > 4 MW							
Secondary	489-S	1	14,864	$549,126	$521,325	($27,802)	
Primary	489-P	9	506,343	$7,589,496	$6,456,978	($1,132,518)	
Subtransmission	489-T	3	333,091	$3,993,810	$3,095,411	($898,399)	
DIRECT ACCESS TOTALS		214	1,511,253	$28,757,552	$24,608,250	($4,149,301)	
COS AND DA CYCLE TOTALS		847,248	19,167,715	$1,759,682,399	$1,841,174,037	$81,491,639	4.6%

PORTLAND GENERAL ELECTRIC
Effect of proposed rate change on Monthly Bills
Tariff Schedule 7

	Net Monthly Bill		
kWh	Current Prices	Proposed Prices	Percent Difference
50	$16.37	$17.35	6.0%
100	$21.57	$22.45	4.1%
200	$32.02	$32.75	2.3%
250	$37.26	$37.93	1.8%
300	$42.46	$43.05	1.4%
400	$52.90	$53.35	0.9%
500	$63.36	$63.65	0.5%
600	$73.78	$73.93	0.2%
700	$84.22	$84.22	0.0%
800	$94.67	$94.52	-0.2%
840	$98.84	$98.64	-0.2%
900	$105.11	$104.83	-0.3%
1,000	$115.54	$115.11	-0.4%
1,100	$127.53	$127.05	-0.4%
1,200	$139.53	$139.02	-0.4%
1,300	$151.53	$150.97	-0.4%
1,400	$163.54	$162.93	-0.4%
1,500	$175.55	$174.89	-0.4%
1,600	$187.51	$186.81	-0.4%
1,700	$199.52	$198.77	-0.4%
1,800	$211.52	$210.73	-0.4%
2,000	$235.51	$234.63	-0.4%
2,300	$271.50	$270.50	-0.4%
2,750	$325.50	$324.30	-0.4%
3,000	$355.48	$354.16	-0.4%
3,500	$415.48	$413.93	-0.4%
4,000	$475.44	$473.68	-0.4%
4,500	$535.45	$533.46	-0.4%
5,000	$595.41	$593.20	-0.4%
7,500	$895.35	$892.03	-0.4%
10,000	$1,195.24	$1,190.82	-0.4%

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	$68.45	$68.72	0.4%	$65.11	$64.96	-0.2%
600	$79.22	$79.33	0.1%	$75.21	$74.82	-0.5%
700	$90.01	$89.97	0.0%	$85.34	$84.71	-0.7%
800	$100.78	$100.62	-0.2%	$95.45	$94.60	-0.9%
900	$111.60	$111.28	-0.3%	$105.59	$104.51	-1.0%
1,000	$122.40	$121.92	-0.4%	$115.73	$114.40	-1.1%
1,500	$176.43	$175.19	-0.7%	$166.42	$163.91	-1.5%
1,750	$203.39	$201.77	-0.8%	$191.71	$188.60	-1.6%
2,000	$230.38	$228.38	-0.9%	$217.03	$213.35	-1.7%
2,500	$284.41	$281.66	-1.0%	$267.72	$262.86	-1.8%
3,500	$392.39	$388.12	-1.1%	$369.03	$361.81	-2.0%
4,000	$446.34	$441.32	-1.1%	$419.64	$411.24	-2.0%
4,500	$500.37	$494.59	-1.2%	$470.33	$460.75	-2.0%
5,000	$554.32	$547.78	-1.2%	$520.95	$510.19	-2.1%
6,000	$631.55	$623.80	-1.2%	$591.50	$578.69	-2.2%
7,000	$708.77	$699.82	-1.3%	$662.05	$647.19	-2.2%
8,000	$786.00	$775.84	-1.3%	$732.60	$715.69	-2.3%
9,000	$863.22	$851.86	-1.3%	$803.15	$784.19	-2.4%
10,000	$940.45	$927.88	-1.3%	$873.70	$852.69	-2.4%
14,000	$1,249.35	$1,231.96	-1.4%	$1,155.90	$1,126.69	-2.5%
15,000	$1,326.57	$1,307.98	-1.4%	$1,226.46	$1,195.19	-2.5%
20,000	$1,712.70	$1,688.08	-1.4%	$1,579.21	$1,537.70	-2.6%
21,900	$1,859.42	$1,832.53	-1.4%	$1,713.25	$1,667.86	-2.6%

PORTLAND GENERAL ELECTRIC
Effect of proposed rate change on Monthly Bills
Tariff Schedule 32, 3-phase Service

kWh	Net Monthly Bill (without RPA credit) Current Prices	Net Monthly Bill (without RPA credit) Proposed Prices	Net Monthly Bill (without RPA credit) Percent Difference	Net Monthly Bill (with RPA credit) Current Prices	Net Monthly Bill (with RPA credit) Proposed Prices	Net Monthly Bill (with RPA credit) Percent Difference
500	$72.57	$73.87	1.8%	$69.23	$70.11	1.3%
600	$83.34	$84.48	1.4%	$79.33	$79.97	0.8%
700	$94.13	$95.12	1.1%	$89.46	$89.86	0.4%
800	$104.90	$105.77	0.8%	$99.57	$99.75	0.2%
900	$115.72	$116.43	0.6%	$109.71	$109.66	0.0%
1,000	$126.52	$127.07	0.4%	$119.85	$119.55	-0.3%
1,500	$180.55	$180.34	-0.1%	$170.54	$169.06	-0.9%
1,750	$207.51	$206.92	-0.3%	$195.83	$193.75	-1.1%
2,000	$234.50	$233.53	-0.4%	$221.15	$218.50	-1.2%
2,500	$288.53	$286.81	-0.6%	$271.84	$268.01	-1.4%
3,500	$396.51	$393.27	-0.8%	$373.15	$366.96	-1.7%
4,000	$450.46	$446.47	-0.9%	$423.76	$416.39	-1.7%
4,500	$504.49	$499.74	-0.9%	$474.45	$465.90	-1.8%
5,000	$558.44	$552.93	-1.0%	$525.07	$515.34	-1.9%
6,000	$635.67	$628.95	-1.1%	$595.62	$583.84	-2.0%
7,000	$712.89	$704.97	-1.1%	$666.17	$652.34	-2.1%
8,000	$790.12	$780.99	-1.2%	$736.72	$720.84	-2.2%
9,000	$867.34	$857.01	-1.2%	$807.27	$789.34	-2.2%
10,000	$944.57	$933.03	-1.2%	$877.82	$857.84	-2.3%
14,000	$1,253.47	$1,237.11	-1.3%	$1,160.02	$1,131.84	-2.4%
15,000	$1,330.69	$1,313.13	-1.3%	$1,230.58	$1,200.34	-2.5%
20,000	$1,716.82	$1,693.23	-1.4%	$1,583.33	$1,542.85	-2.6%
21,900	$1,863.54	$1,837.68	-1.4%	$1,717.37	$1,673.01	-2.6%

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	$38.69	$44.50	15.0%	$38.36	$44.12	15.0%
10	100	$46.49	$52.96	13.9%	$45.82	$52.21	13.9%
10	500	$108.79	$120.56	10.8%	$105.45	$116.80	10.8%
10	1,000	$176.31	$194.74	10.5%	$169.63	$187.22	10.4%
10	2,000	$311.41	$343.11	10.2%	$298.06	$328.07	10.1%
10	5,000	$716.70	$788.24	10.0%	$683.33	$750.64	9.9%
20	100	$46.49	$52.96	13.9%	$45.82	$52.21	13.9%
20	200	$62.05	$69.85	12.6%	$60.71	$68.34	12.6%
20	500	$108.79	$120.56	10.8%	$105.45	$116.80	10.8%
20	1,000	$186.60	$205.03	9.9%	$179.92	$197.51	9.8%
20	2,000	$321.70	$353.40	9.9%	$308.35	$338.36	9.7%
20	5,000	$726.99	$798.53	9.8%	$693.62	$760.93	9.7%
20	8,000	$1,132.29	$1,243.65	9.8%	$1,078.89	$1,183.50	9.7%
30	150	$54.25	$61.39	13.2%	$53.25	$60.25	13.1%
30	500	$108.79	$120.56	10.8%	$105.45	$116.80	10.8%
30	1,000	$186.60	$205.03	9.9%	$179.92	$197.51	9.8%
30	3,000	$467.11	$512.09	9.6%	$447.08	$489.53	9.5%
30	5,000	$737.30	$808.84	9.7%	$703.93	$771.24	9.6%
30	8,000	$1,142.60	$1,253.96	9.7%	$1,089.20	$1,193.81	9.6%
30	10,000	$1,412.80	$1,550.71	9.8%	$1,346.05	$1,475.52	9.6%
30	15,000	$2,088.29	$2,292.59	9.8%	$1,988.17	$2,179.81	9.6%

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	$632.03	$696.72	10.2%	$597.93	$658.30	10.1%
40%	35	10,220	$1,191.96	$1,316.15	10.4%	$1,123.74	$1,239.30	10.3%
60%	35	15,330	$1,751.88	$1,935.61	10.5%	$1,649.56	$1,820.34	10.4%
80%	35	20,440	$2,311.79	$2,555.04	10.5%	$2,175.36	$2,401.36	10.4%
20%	50	7,300	$887.45	$977.65	10.2%	$838.73	$922.76	10.0%
40%	50	14,600	$1,687.35	$1,862.58	10.4%	$1,589.90	$1,752.80	10.2%
60%	50	21,900	$2,487.24	$2,747.50	10.5%	$2,341.07	$2,582.83	10.3%
80%	50	29,200	$3,287.11	$3,632.42	10.5%	$3,092.22	$3,412.87	10.4%
20%	70	10,220	$1,228.01	$1,352.21	10.1%	$1,159.79	$1,275.36	10.0%
40%	70	20,440	$2,347.84	$2,591.10	10.4%	$2,211.41	$2,437.42	10.2%
60%	70	30,660	$3,467.70	$3,830.02	10.4%	$3,263.06	$3,599.48	10.3%
80%	70	40,880	$4,587.52	$5,068.91	10.5%	$4,314.68	$4,761.54	10.4%
20%	100	14,600	$1,738.84	$1,914.07	10.1%	$1,641.39	$1,804.29	9.9%
40%	100	29,200	$3,338.61	$3,683.91	10.3%	$3,143.72	$3,464.36	10.2%
60%	100	43,800	$4,938.39	$5,453.79	10.4%	$4,646.05	$5,124.46	10.3%
80%	100	58,400	$6,538.17	$7,223.63	10.5%	$6,148.38	$6,784.52	10.3%
20%	200	29,200	$3,441.61	$3,786.91	10.0%	$3,246.72	$3,567.36	9.9%
40%	200	58,400	$6,641.17	$7,326.63	10.3%	$6,251.38	$6,887.52	10.2%
60%	200	87,600	$9,840.74	$10,866.37	10.4%	$9,256.06	$10,207.71	10.3%
80%	200	116,800	$13,040.29	$14,406.09	10.5%	$12,260.73	$13,527.87	10.3%

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	$158.17	$161.04	1.8%	$151.49	$153.52	1.3%
3,000	$423.00	$431.62	2.0%	$402.98	$409.06	1.5%
5,000	$687.83	$702.20	2.1%	$654.46	$664.61	1.6%
7,000	$952.66	$972.78	2.1%	$905.94	$920.15	1.6%
10,000	$1,349.91	$1,378.65	2.1%	$1,283.17	$1,303.46	1.6%
13,000	$1,747.16	$1,784.52	2.1%	$1,660.39	$1,686.77	1.6%
14,000	$1,879.58	$1,919.81	2.1%	$1,786.14	$1,814.54	1.6%
16,000	$2,144.41	$2,190.39	2.1%	$2,037.62	$2,070.09	1.6%
21,000	$2,806.49	$2,866.84	2.2%	$2,666.33	$2,708.94	1.6%
25,000	$3,336.16	$3,408.00	2.2%	$3,169.30	$3,220.03	1.6%
30,000	$3,998.24	$4,084.45	2.2%	$3,798.01	$3,858.88	1.6%
35,000	$4,660.32	$4,760.90	2.2%	$4,426.72	$4,497.74	1.6%
40,000	$5,322.40	$5,437.35	2.2%	$5,055.43	$5,136.59	1.6%
45,000	$5,984.48	$6,113.80	2.2%	$5,684.14	$5,775.45	1.6%
50,000	$6,646.58	$6,790.25	2.2%	$6,312.86	$6,414.30	1.6%
75,000	$9,956.97	$10,172.50	2.2%	$9,456.39	$9,608.58	1.6%
100,000	$13,267.38	$13,554.75	2.2%	$12,599.94	$12,802.85	1.6%
150,000	$19,888.21	$20,319.25	2.2%	$18,887.05	$19,191.40	1.6%
200,000	$26,509.01	$27,083.75	2.2%	$25,174.13	$25,579.95	1.6%
300,000	$39,750.64	$40,612.75	2.2%	$37,748.32	$38,357.05	1.6%
400,000	$52,992.27	$54,141.75	2.2%	$50,322.51	$51,134.15	1.6%
500,000	$66,233.90	$67,670.75	2.2%	$62,896.70	$63,911.25	1.6%
750,000	$96,244.84	$98,400.10	2.2%	$91,239.04	$92,760.85	1.7%
1,000,000	$128,317.85	$131,191.55	2.2%	$121,643.45	$123,672.55	1.7%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 83, Secondary, 3 phase service.
Bill comparison assumes 63% on peak and 37% off peak energy consumption

			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	$696.35	$692.15	-0.6%	$652.50	$642.76	-1.5%
30%	50	10,950	$1,131.06	$1,124.07	-0.6%	$1,057.98	$1,041.73	-1.5%
30%	75	16,425	$1,674.43	$1,663.96	-0.6%	$1,564.81	$1,540.46	-1.6%
30%	100	21,900	$2,217.81	$2,203.83	-0.6%	$2,071.64	$2,039.17	-1.6%
30%	135	29,565	$2,978.51	$2,959.64	-0.6%	$2,781.19	$2,737.35	-1.6%
30%	175	38,325	$3,847.93	$3,823.47	-0.6%	$3,592.13	$3,535.30	-1.6%
30%	200	43,800	$4,391.32	$4,363.35	-0.6%	$4,098.98	$4,034.02	-1.6%
50%	30	10,950	$1,019.62	$1,001.71	-1.8%	$946.53	$919.37	-2.9%
50%	50	18,250	$1,669.83	$1,639.97	-1.8%	$1,548.02	$1,502.74	-2.9%
50%	75	27,375	$2,482.58	$2,437.82	-1.8%	$2,299.87	$2,231.98	-3.0%
50%	100	36,500	$3,295.35	$3,235.64	-1.8%	$3,051.74	$2,961.20	-3.0%
50%	135	49,275	$4,433.19	$4,352.61	-1.8%	$4,104.31	$3,982.11	-3.0%
50%	175	63,875	$5,733.60	$5,629.14	-1.8%	$5,307.27	$5,148.86	-3.0%
50%	200	73,000	$6,546.36	$6,426.96	-1.8%	$6,059.13	$5,878.08	-3.0%
70%	30	15,330	$1,342.86	$1,311.24	-2.4%	$1,240.54	$1,195.97	-3.6%
70%	50	25,550	$2,208.57	$2,155.87	-2.4%	$2,038.04	$1,963.76	-3.6%
70%	75	38,325	$3,290.70	$3,211.65	-2.4%	$3,034.90	$2,923.48	-3.7%
70%	100	51,100	$4,372.86	$4,267.43	-2.4%	$4,031.80	$3,883.21	-3.7%
70%	135	68,985	$5,887.85	$5,745.56	-2.4%	$5,427.42	$5,226.86	-3.7%
70%	175	89,425	$7,619.27	$7,434.80	-2.4%	$7,022.42	$6,762.42	-3.7%
70%	200	102,200	$8,701.41	$8,490.57	-2.4%	$8,019.28	$7,722.12	-3.7%
90%	30	19,710	$1,666.11	$1,620.77	-2.7%	$1,534.56	$1,472.57	-4.0%
90%	50	32,850	$2,747.34	$2,671.78	-2.8%	$2,528.09	$2,424.78	-4.1%
90%	75	49,275	$4,098.85	$3,985.52	-2.8%	$3,769.97	$3,615.02	-4.1%
90%	100	65,700	$5,450.37	$5,299.23	-2.8%	$5,011.85	$4,805.24	-4.1%
90%	135	88,695	$7,342.49	$7,138.47	-2.8%	$6,750.51	$6,471.58	-4.1%
90%	175	114,975	$9,504.93	$9,240.46	-2.8%	$8,737.54	$8,375.96	-4.1%
90%	200	131,400	$10,856.45	$10,554.19	-2.8%	$9,979.44	$9,566.19	-4.1%

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

Load Factor	kW	kWh	Net Monthly Bill: Current Prices	Net Monthly Bill: Proposed Prices	Percent Difference
30%	200	43,800	$4,602.65	$4,492.26	-2.4%
30%	300	65,700	$6,522.83	$6,403.62	-1.8%
30%	500	109,500	$10,363.27	$10,226.38	-1.3%
30%	700	153,300	$14,203.67	$14,049.10	-1.1%
30%	800	175,200	$16,123.84	$15,960.43	-1.0%
30%	900	197,100	$18,044.09	$17,871.84	-1.0%
30%	1,000	219,000	$19,964.28	$19,783.19	-0.9%
30%	1,500	328,500	$29,565.34	$29,340.07	-0.8%
30%	2,000	438,000	$39,166.36	$38,896.89	-0.7%
30%	4,000	876,000	$75,228.44	$74,782.21	-0.6%
50%	200	73,000	$6,487.21	$6,316.98	-2.6%
50%	300	109,500	$9,349.75	$9,140.76	-2.2%
50%	500	182,500	$15,074.77	$14,788.24	-1.9%
50%	700	255,500	$20,799.78	$20,435.73	-1.8%
50%	800	292,000	$23,662.25	$23,259.44	-1.7%
50%	900	328,500	$26,524.78	$26,083.21	-1.7%
50%	1,000	365,000	$29,387.27	$28,906.92	-1.6%
50%	1,500	547,500	$43,699.83	$43,025.67	-1.5%
50%	2,000	730,000	$58,012.33	$57,144.35	-1.5%
50%	4,000	1,460,000	$111,129.00	$109,485.74	-1.5%
70%	200	102,200	$8,371.78	$8,141.71	-2.7%
70%	300	153,300	$12,176.63	$11,877.86	-2.5%
70%	500	255,500	$19,786.26	$19,350.11	-2.2%
70%	700	357,700	$27,395.84	$26,822.32	-2.1%
70%	800	408,800	$31,200.67	$30,558.45	-2.1%
70%	900	459,900	$35,005.44	$34,294.54	-2.0%
70%	1,000	511,000	$38,810.25	$38,030.65	-2.0%
70%	1,500	766,500	$55,784.98	$54,661.93	-2.0%
70%	2,000	1,022,000	$74,114.88	$72,648.39	-2.0%
70%	4,000	2,044,000	$146,967.57	$144,127.28	-1.9%
90%	200	131,400	$10,256.41	$9,966.48	-2.8%
90%	300	197,100	$15,003.53	$14,614.98	-2.6%
90%	500	328,500	$24,497.74	$23,911.97	-2.4%
90%	700	459,900	$33,991.92	$33,208.92	-2.3%
90%	800	525,600	$38,739.03	$37,857.40	-2.3%
90%	900	591,300	$43,486.15	$42,505.91	-2.3%
90%	1,000	657,000	$48,233.24	$47,154.38	-2.2%
90%	1,500	985,500	$69,333.94	$67,762.01	-2.3%
90%	2,000	1,314,000	$92,034.16	$89,969.16	-2.2%
90%	4,000	2,628,000	$182,806.13	$178,768.82	-2.2%

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

			Net Monthly Bill		
Load Factor	kW	kWh	Current Prices	Proposed Prices	Percent Difference
30%	200	43,800	$4,524.07	$4,451.77	-1.6%
30%	300	65,700	$6,389.54	$6,327.44	-1.0%
30%	500	109,500	$10,120.51	$10,078.81	-0.4%
30%	700	153,300	$13,851.48	$13,830.17	-0.2%
30%	800	175,200	$15,716.92	$15,705.81	-0.1%
30%	900	197,100	$17,582.43	$17,581.52	0.0%
30%	1,000	219,000	$19,447.89	$19,457.18	0.0%
30%	1,500	328,500	$28,775.30	$28,835.58	0.2%
30%	2,000	438,000	$38,102.68	$38,213.96	0.3%
30%	4,000	876,000	$73,070.18	$73,385.44	0.4%
50%	200	73,000	$6,359.03	$6,244.02	-1.8%
50%	300	109,500	$9,142.01	$9,015.85	-1.4%
50%	500	182,500	$14,707.94	$14,559.47	-1.0%
50%	700	255,500	$20,273.87	$20,103.08	-0.8%
50%	800	292,000	$23,056.82	$22,874.88	-0.8%
50%	900	328,500	$25,839.80	$25,646.70	-0.7%
50%	1,000	365,000	$28,622.75	$28,418.50	-0.7%
50%	1,500	547,500	$42,537.59	$42,277.57	-0.6%
50%	2,000	730,000	$56,452.40	$56,136.60	-0.6%
50%	4,000	1,460,000	$107,978.23	$107,439.34	-0.5%
70%	200	102,200	$8,193.99	$8,036.27	-1.9%
70%	300	153,300	$11,894.48	$11,704.25	-1.6%
70%	500	255,500	$19,295.37	$19,040.12	-1.3%
70%	700	357,700	$26,696.26	$26,375.99	-1.2%
70%	800	408,800	$30,396.72	$30,043.95	-1.2%
70%	900	459,900	$34,097.18	$33,711.88	-1.1%
70%	1,000	511,000	$37,797.61	$37,379.82	-1.1%
70%	1,500	766,500	$54,250.55	$53,670.22	-1.1%
70%	2,000	1,022,000	$72,058.69	$71,315.82	-1.0%
70%	4,000	2,044,000	$142,824.29	$141,431.23	-1.0%
90%	200	131,400	$10,028.97	$9,828.55	-2.0%
90%	300	197,100	$14,646.93	$14,392.64	-1.7%
90%	500	328,500	$23,882.80	$23,520.78	-1.5%
90%	700	459,900	$33,118.68	$32,648.92	-1.4%
90%	800	525,600	$37,736.59	$37,212.98	-1.4%
90%	900	591,300	$42,354.55	$41,777.09	-1.4%
90%	1,000	657,000	$46,972.47	$46,341.14	-1.3%
90%	1,500	985,500	$67,427.32	$66,526.67	-1.3%
90%	2,000	1,314,000	$89,481.72	$88,311.76	-1.3%
90%	4,000	2,628,000	$177,670.34	$175,423.13	-1.3%

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

			Net Monthly Bill		
Load Factor	kW	kWh	Current Prices	Proposed Prices	Percent Difference
30%	4,000	876,000	$76,652.56	$76,129.73	-0.7%
30%	7,500	1,642,500	$136,994.44	$135,824.87	-0.9%
30%	10,000	2,190,000	$180,051.45	$178,419.93	-0.9%
30%	15,000	3,285,000	$266,165.53	$263,610.10	-1.0%
30%	20,000	4,380,000	$352,279.61	$348,800.27	-1.0%
50%	4,000	1,460,000	$111,133.54	$109,046.76	-1.9%
50%	7,500	2,737,500	$201,530.01	$197,428.04	-2.0%
50%	10,000	3,650,000	$266,098.89	$260,557.49	-2.1%
50%	15,000	5,475,000	$395,236.69	$386,816.44	-2.1%
50%	20,000	7,300,000	$524,374.48	$513,075.38	-2.2%
70%	4,000	2,044,000	$145,552.51	$141,901.78	-2.5%
70%	7,500	3,832,500	$266,065.59	$259,031.21	-2.6%
70%	10,000	5,110,000	$352,146.33	$342,695.05	-2.7%
70%	15,000	7,665,000	$524,307.84	$510,022.77	-2.7%
70%	20,000	10,220,000	$696,469.35	$677,350.49	-2.7%
90%	4,000	2,628,000	$179,971.48	$174,756.80	-2.9%
90%	7,500	4,927,500	$330,601.17	$320,634.37	-3.0%
90%	10,000	6,570,000	$438,193.76	$424,832.60	-3.0%
90%	15,000	9,855,000	$653,378.99	$633,229.10	-3.1%
90%	20,000	13,140,000	$868,564.22	$841,625.60	-3.1%

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	$74,070.56	$74,269.55	0.3%
30%	7,500	1,642,500	$132,486.64	$132,850.75	0.3%
30%	10,000	2,190,000	$174,168.09	$174,650.13	0.3%
30%	15,000	3,285,000	$257,531.04	$258,248.95	0.3%
30%	20,000	4,380,000	$340,893.99	$341,847.77	0.3%
50%	4,000	1,460,000	$107,468.80	$106,585.06	-0.8%
50%	7,500	2,737,500	$194,992.09	$193,326.06	-0.9%
50%	10,000	3,650,000	$257,508.69	$255,283.89	-0.9%
50%	15,000	5,475,000	$382,541.94	$379,199.59	-0.9%
50%	20,000	7,300,000	$507,575.18	$503,115.28	-0.9%
70%	4,000	2,044,000	$140,805.03	$138,838.56	-1.4%
70%	7,500	3,832,500	$257,497.54	$253,801.38	-1.4%
70%	10,000	5,110,000	$340,849.29	$335,917.65	-1.4%
70%	15,000	7,665,000	$507,552.83	$500,150.22	-1.5%
70%	20,000	10,220,000	$674,256.37	$664,382.79	-1.5%
90%	4,000	2,628,000	$174,141.27	$171,092.06	-1.8%
90%	7,500	4,927,500	$320,002.98	$314,276.70	-1.8%
90%	10,000	6,570,000	$424,189.88	$416,551.40	-1.8%
90%	15,000	9,855,000	$632,563.72	$621,100.85	-1.8%
90%	20,000	13,140,000	$840,937.56	$825,650.30	-1.8%

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

			Net Monthly Bill		
Load Factor	kW	kWh	Current Prices	Proposed Prices	Percent Difference
30%	4,000	876,000	$70,615.40	$68,668.17	-2.8%
30%	5,000	1,095,000	$86,321.40	$83,861.61	-2.8%
30%	10,000	2,190,000	$164,541.41	$159,518.82	-3.1%
30%	20,000	4,380,000	$320,981.41	$310,833.23	-3.2%
30%	40,000	8,760,000	$633,861.42	$613,462.06	-3.2%
30%	50,000	10,950,000	$790,301.43	$764,776.48	-3.2%
30%	70,000	15,330,000	$1,103,181.44	$1,067,405.31	-3.2%
50%	4,000	1,460,000	$103,550.47	$100,538.54	-2.9%
50%	5,000	1,825,000	$127,412.74	$123,622.08	-3.0%
50%	10,000	3,650,000	$246,724.08	$239,039.76	-3.1%
50%	20,000	7,300,000	$485,346.75	$469,875.12	-3.2%
50%	40,000	14,600,000	$962,592.10	$931,545.84	-3.2%
50%	50,000	18,250,000	$1,201,214.78	$1,162,381.20	-3.2%
50%	70,000	25,550,000	$1,678,460.13	$1,624,051.92	-3.2%
70%	4,000	2,044,000	$136,423.54	$132,346.92	-3.0%
70%	5,000	2,555,000	$168,504.07	$163,382.55	-3.0%
70%	10,000	5,110,000	$328,906.75	$318,560.70	-3.1%
70%	20,000	10,220,000	$649,712.09	$628,917.01	-3.2%
70%	40,000	20,440,000	$1,291,322.78	$1,249,629.62	-3.2%
70%	50,000	25,550,000	$1,612,128.13	$1,559,985.92	-3.2%
70%	70,000	35,770,000	$2,253,738.82	$2,180,698.53	-3.2%
90%	4,000	2,628,000	$169,296.61	$164,155.30	-3.0%
90%	5,000	3,285,000	$209,595.41	$203,143.02	-3.1%
90%	10,000	6,570,000	$411,089.42	$398,081.65	-3.2%
90%	20,000	13,140,000	$814,077.43	$787,958.90	-3.2%
90%	40,000	26,280,000	$1,620,053.46	$1,567,713.39	-3.2%
90%	50,000	32,850,000	$2,023,041.48	$1,957,590.64	-3.2%
90%	70,000	45,990,000	$2,829,017.51	$2,737,345.14	-3.2%

PORTLAND GENERAL ELECTRIC

Effect of Proposed Rate Change on Monthly Bills

Tariff Schedule 90, 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
80%	4,000	2,336,000	$154,300.75	$168,522.83	9.2%
80%	5,000	2,920,000	$191,808.49	$204,091.04	6.4%
80%	10,000	5,840,000	$379,347.18	$381,932.07	0.7%
80%	20,000	11,680,000	$754,424.57	$737,614.14	-2.2%
80%	40,000	23,360,000	$1,504,579.34	$1,448,978.29	-3.7%
80%	60,000	35,040,000	$2,254,734.10	$2,160,342.43	-4.2%
80%	80,000	46,720,000	$3,004,888.87	$2,871,706.58	-4.4%
90%	4,000	2,628,000	$170,968.87	$184,195.43	7.7%
90%	5,000	3,285,000	$212,643.64	$223,681.79	5.2%
90%	10,000	6,570,000	$421,017.48	$421,113.58	0.0%
90%	20,000	13,140,000	$837,765.16	$815,977.16	-2.6%
90%	40,000	26,280,000	$1,671,260.53	$1,605,704.32	-3.9%
90%	60,000	39,420,000	$2,504,755.89	$2,395,431.49	-4.4%
90%	80,000	52,560,000	$3,338,251.26	$3,185,158.65	-4.6%

Note: Current prices do not include load following/integration credit

PORTLAND GENERAL ELECTRIC
MARGINAL ENERGY COSTS

Schedule	Busbar Energy (MWh)	Marginal Energy Cost
Schedule 7	7,969,633	$419,840,573
Schedule 15	17,066	$787,636
Schedule 32	1,666,742	$86,120,231
Schedule 38	46,551	$2,486,765
Schedule 47	19,502	$1,042,147
Schedule 49	73,837	$3,897,406
Schedule 83	2,932,325	$152,587,547
Schedule 85	2,344,524	$120,889,319
Schedule 85 1-4 MW	927,959	$47,466,348
Schedule 89	1,164,883	$58,482,927
Schedule 90	1,539,063	$77,032,786
Schedule 91	103,745	$4,788,047
Schedule 92	3,547	$176,735
Totals	18,809,377	$975,598,466

PORTLAND GENERAL ELECTRIC
MARGINAL CAPACITY COSTS

SCCT Proxy Capital Cost $/kW

1	SCCT Installed Cost	$/kW	$812
2	Real Carrying Charge		10.10%
3	Annualized SCCT Cost	$/kW-yr	$82.01
4	Fixed O&M	$/kW-yr	$7.46
5	Reserve Margin (12%)	$/kW-yr	$10.74
6	Total	$/kW-yr	$100.20

PORTLAND GENERAL ELECTRIC
RATE DESIGN INPUT
SUMMARY - ALLOCATION OF 2015 COSTS TO RATE SCHEDULES ($000)

	Energy-Based Charges					Trans. & Related Charges			Distribution Demand & Facilities Charges				
Grouping	Power Supply	Franchise Fees	Trojan	Sch 129	Subtotal	Transmission	Ancillary Services	Subtotal	Substation	Subtrans.	Feeder Backbone	Feeder Facilities	Subtotal
Schedule 7	$466,521	$21,866	$1,463	($585)	$22,743	$16,756	$2,202	$18,958	$35,653	$19,229	$61,660	$65,334	$181,875
Schedule 15	$793	$93	$2	($1)	$95	$24	$4	$28	$78	$42	$140	$95	$356
Schedule 32	$90,623	$4,187	$284	($122)	$4,349	$3,021	$429	$3,450	$6,058	$3,267	$12,063	$14,166	$35,554
Schedule 38	$2,536	$142	$8	($3)	$147	$80	$12	$92	$382	$206	$923	$844	$2,356
Schedule 47	$1,315	$125	$4	($1)	$128	$56	$6	$62	$265	$143	$1,337	$1,108	$2,854
Schedule 49	$4,740	$393	$15	($5)	$403	$191	$22	$214	$1,005	$542	$5,207	$3,172	$9,925
Schedule 83													
Secondary	$158,883	$5,882	$498	($214)	$6,165	$5,221	$753	$5,974	$10,658	$5,748	$18,541	$10,682	$45,629
Schedule 85													
Secondary		$3,978	$416	($3,303)	$1,091								
Primary		$426	$48	($392)	$82								
Class Total	$122,534					$3,973	$587	$4,561	$9,537	$5,144	$14,344	$6,347	$35,373
Schedule 85 1-4 MW													
Secondary		$874	$91	($726)	$239								
Primary		$897	$101	($825)	$173								
Class Total	$50,229					$1,511	$228	$1,739	$3,665	$1,977	$5,715	$1,781	$13,138
Schedule 89 GT 4 MW													
Secondary		$6	$2	($21)	($12)						$115		$115
Primary		$1,647	$232	($1,996)	($117)						$3,095		$3,095
Subtransmission		$457	$87	($763)	($218)						$979		$979
Class Total	$58,445					$1,723	$273	$1,996	$3,905	$3,359			$7,265
Schedule 90-P	$73,605	$2,151	$231	($2,042)	$340	$2,229	$358	$2,587	$3,800	$2,049	$1,451		$7,300
Schedules 91 & 95	$4,821	$429	$15	($8)	$437	$148	$23	$171	$475	$256	$852	$579	$2,162
Schedules 92	$173	$6	$1	($0)	$6	$5	$1	$6	$7	$4	$13	$5	$30
Totals	$1,035,218	$43,560	$3,499	($11,009)	$36,050	$34,939	$4,898	$39,836	$75,489	$41,968	$126,435	$104,112	$348,005

PORTLAND GENERAL ELECTRIC
RATE DESIGN INPUTS (CONTINUED)
SUMMARY - ALLOCATION OF 2015 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	$92,593	$22	$7,514	$1	$1,743	$0	$48,614	$6	$39,358	$5	$189,821	$33		$189,855	$879,952
Schedule 15	$244		$24		$0		$138		$76		$482	$0	$1,997	$2,479	$3,751
Schedule 32	$8,866	$13,961	$259	$168	$201	$130	$3,358	$2,181	$3,083	$2,002	$15,767	$18,443		$34,210	$168,185
Schedule 38	$17	$453	$0	$1	$2	$24	$4	$37	$4	$42	$28	$557		$584	$5,715
Schedule 47	$18	$379	$1	$9	$1	$9	$11	$147	$8	$106	$38	$649		$688	$5,046
Schedule 49	$1	$381	$0	$21	$0	$8	$0	$91	$0	$51	$1	$552		$553	$15,835
Schedule 83															
Secondary	$339	$14,609	$11	$173	$17	$272	$100	$1,570	$130	$2,051	$598	$18,674		$19,272	$235,923
Schedule 85															
Secondary		$3,000		$36		$89		$858		$2,650	$0	$6,631		$6,631	
Primary		$442		$4		$10		$101		$311	$0	$868		$868	$171,140
Schedule 85 1-4 MW															
Secondary		$441		$11		$3		$46		$681	$0	$1,182		$1,182	
Primary		$235		$11		$4		$47		$696	$0	$993		$993	$67,693
Schedule 89 GT 4 MW															
Secondary		$19		$13		$0		$1		$98	$0	$131		$131	
Primary		$146		$349		$0		$14		$2,644	$0	$3,154		$3,154	
Subtransmission		$183		$104		$0		$4		$784	$0	$1,074		$1,074	$75,906
Schedule 90-P		$22		$0		$0		$2		$392	$0	$415		$415	$84,247
Schedules 91 & 95	$1,656			$0		$0	$98		$120		$1,874	$0	$7,796	$9,669	$17,260
Schedule 92		$20		$0		$0		$8		$5	$0	$33		$33	$247
Totals	$103,733	$34,313	$7,809	$900	$1,964	$550	$52,323	$5,111	$42,779	$12,515	$208,609	$53,390	$9,792	$271,791	$1,730,900

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2015

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	$189,821	739,963	Customers	$21.38	per cust. per mo.	$189,845
Three-Phase	$33	85	Customers	$32.56	per cust. per mo.	$33
Trans. & Rel. Serv. Charge	$18,958	7,462,740	MWh	2.54	mills/kWh	$18,955
Distribution Charge	$181,875	7,462,740	MWh	24.37	mills/kWh	$181,867
Franchise Fees & Other	$22,743	7,462,740	MWh	3.05	mills/kWh	$22,761
Energy Charge	$466,521	7,462,740	MWh	62.51	mills/kWh	$466,496
Subtotal	$879,952					$879,958
Pricing						
Functional Costs						
Basic Charge						
Single-Phase		739,963	Customers	$11.00	per cust. per mo.	$97,675
Three-Phase		85	Customers	$11.00	per cust. per mo.	$11
Trans. & Rel. Serv. Charge		7,462,740	MWh	2.54	mills/kWh	$18,955
Distribution Charge		7,462,740	MWh	36.72	mills/kWh	$274,032
System Usage Charge Calculation						
Franchise Fees & Other		7,462,740	MWh	3.05	mills/kWh	$22,761
Cust Impact Offset		7,462,740	MWh	0.48	mills/kWh	$3,582
System Usage Charge		7,462,740	MWh	3.53	mills/kWh	$26,343
Energy Charge						
Block 1 (First 500 kWh)		3,970,232	MWh	61.25	mills/kWh	$243,177
Block 2 (501-1,000 kWh)		2,190,115	MWh	61.25	mills/kWh	$134,145
Block 3 (Over 1,000 kWh)		1,302,393	MWh	68.47	mills/kWh	$89,175
Subtotal						$883,513
					w/o CIO	$879,931
SCHEDULE 15						
Outdoor Area Lighting						
Allocations						
Functional Costs						
Basic Charge	$482	2,254	Customers	$17.83	per cust. per mo.	$482
Trans. & Rel. Serv. Charge	$28	15,972	MWh	1.76	mills/kWh	$28
Distribution Charge	$356	15,972	MWh	22.27	mills/kWh	$356
Franchise Fees & Other	$95	15,972	MWh	5.92	mills/kWh	$95
Energy Charge	$793	15,972	MWh	49.66	mills/kWh	$793
Fixed Charges	$1,997	15,972	MWh			$1,997
Subtotal	$3,751					$3,751
Pricing						
Functional Costs						
Trans. & Rel. Serv. Charge		15,972	MWh	1.76	mills/kWh	$28
Distribution Charge		15,972	MWh	52.47	mills/kWh	$838
System Usage Charge Calc						
Franchise Fees & Other		15,972	MWh	5.92	mills/kWh	$95
Cust Impact Offset		15,972	MWh	(10.58)	mills/kWh	($169)
System Usage Charge		15,972	MWh	(4.66)	mills/kWh	($74)
Energy Charge		15,972	MWh	49.66	mills/kWh	$793
Fixed Charges		15,972	MWh			$1,997
Subtotal						$3,582
					w/o CIO	$3,751

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2015

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	$15,767	54,240	Customers	$24.22	per cust. per mo.	$15,764
Three-Phase	$18,443	35,231	Customers	$43.63	per cust. per mo.	$18,445
Trans. & Rel. Serv. Charge	$3,450	1,556,500	MWh	2.22	mills/kWh	$3,455
Distribution Charge	$35,554	1,556,500	MWh	22.84	mills/kWh	$35,550
Franchise Fees & Other	$4,349	1,556,500	MWh	2.79	mills/kWh	$4,343
Energy Charge	$90,623	1,556,500	MWh	58.22	mills/kWh	$90,619
Subtotal	$168,185					$168,178
Pricing						
Functional Costs						
Basic Charge						
Single-Phase		54,240	Customers	$15.00	per cust. per mo.	$9,763
Three-Phase		35,231	Customers	$20.00	per cust. per mo.	$8,455
Trans. & Rel. Serv. Charge		1,556,500	MWh	2.22	mills/kWh	$3,455
Distribution Charge						
First 5 MWh		1,375,187	MWh	36.56	mills/kWh	$50,277
Over 5 MWh		181,314	MWh	7.00	mills/kWh	$1,269
System Usage Charge Calc						
Franchise Fees & Other		1,556,500	MWh	2.79	mills/kWh	$4,343
Cust Impact Offset		1,556,500	MWh	0.48	mills/kWh	$747
System Usage Charge		1,556,500	MWh	3.27	mills/kWh	$5,090
Energy Charge		1,556,500	MWh	58.22	mills/kWh	$90,619
Subtotal						$168,929
					w/o CIO	$168,182
SCHEDULE 38						
Time-of-Day G.S. >30 kW						
Allocations						
Functional Costs						
Basic						
Single-Phase	$28	51	Customers	$44.97	per cust. per mo.	$28
Three-Phase	$557	510	Customers	$90.96	per cust. per mo.	$557
Trans. & Rel. Serv. Charge	$92	43,599	MWh	2.10	per cust. per mo.	$92
Distribution Charges	$2,356	43,599	MWh	54.04	per cust. per mo.	$2,356
Franchise Fees & Other	$147	43,599	MWh	3.36	mills/kWh	$146
Energy Charge	$2,536	43,599	MWh	58.17	mills/kWh	$2,536
Subtotal	$5,715					$5,714
Pricing						
Functional Costs						
Basic						
Single-Phase		51	Customers	$25.00	per cust. per mo.	$15
Three-Phase		510	Customers	$25.00	per cust. per mo.	$153
Trans. & Rel. Serv. Charge		43,599	MWh	2.10	mills/kWh	$92
Distribution Charges		43,599	MWh	62.73	mills/kWh	$2,735
System Usage Charge						
Franchise Fees & Other		43,599	MWh	3.36	mills/kWh	$146
Cust Impact Offset		43,599	MWh	0.48	mills/kWh	$21
System Usage Charge		43,599	MWh	3.84	mills/kWh	$167
Energy Charge Calc						
On-Peak (special)		23,060	MWh	62.88	mills/kWh	$1,450
Off-Peak		20,538	MWh	52.88	mills/kWh	$1,086
Reactive Demand Charge		73,734	kVar	$0.50	kVar	$37
Subtotal						$5,735
					w/o CIO	$5,714

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2015

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	$38	208	Customers	$30.69	per cust. per summ. mo.	$38
Three-Phase	$649	2,783	Customers	$38.88	per cust. per summ. mo.	$649
Trans. & Rel. Serv. Charge	$62	18,147	MWh	3.42	mills/kWh	$62
Distribution Charges	$2,854	18,147	MWh	157.25	mills/kWh	$2,854
Franchise Fees & Other	$128	18,147	MWh	7.06	mills/kWh	$128
Energy Charge	$1,315	18,147	MWh	72.46	mills/kWh	$1,315
Subtotal	$5,046					$5,046
Pricing						
Functional Costs						
Basic Charge						
Single-Phase		208	Customers	$35.00	per cust. per summ. mo.	$44
Three-Phase		2,783	Customers	$35.00	per cust. per summ. mo.	$584
Trans. & Rel. Serv. Charge		18,147	MWh	3.42	mills/kWh	$62
Distribution Charge Calc						
First 50 kWh per kW		6,620	MWh	173.23	mills/kWh	$1,147
Over 50 kWh per kW		11,527	MWh	153.23	mills/kWh	$1,766
System Usage Charge Calc						
Franchise Fees & Other		18,147	MWh	7.06	mills/kWh	$128
Cust Impact Offset		18,147	MWh	(97.97)	mills/kWh	($1,778)
System Usage Charge		18,147	MWh	(90.91)	mills/kWh	($1,650)
Energy Charge		18,147	MWh	72.46	mills/kWh	$1,315
Reactive Demand Charge		45	kVar	$0.50	kVar	$0
Subtotal with Consumer Impact Offset						$3,269
					w/o CIO	$5,046
SCHEDULE 49						
Irrig. & Drain. Pump. - > 30 kW						
Allocations						
Functional Costs						
Basic						
Single-Phase	$1	3	Customers	$65.86	per cust. per summ. mo.	$1
Three-Phase	$552	1,326	Customers	$69.39	per cust. per summ. mo.	$552
Trans. & Rel. Serv. Charge	$214	69,025	MWh	3.10	mills/kWh	$214
Distribution Charges	$9,925	69,025	MWh	143.79	mills/kWh	$9,925
Franchise Fees & Other	$403	69,025	MWh	5.84	mills/kWh	$403
Energy Charge	$4,740	69,025	MWh	68.66	mills/kWh	$4,739
Subtotal	$15,835					$15,835
Pricing						
Functional Costs						
Basic Charge						
Single-Phase		3	Customers	$40.00	per cust. per summ. mo.	$1
Three-Phase		1,326	Customers	$40.00	per cust. per summ. mo.	$318
Trans. & Rel. Serv. Charge		69,025	MWh	3.10	mills/kWh	$214
Distribution Charge Calc						
First 50 kWh per kW		20,960	MWh	161.05	mills/kWh	$3,376
Over 50 kWh per kW		48,066	MWh	141.05	mills/kWh	$6,780
System Usage Charge Calc						
Franchise Fees & Other		69,025	MWh	5.84	mills/kWh	$403
Cust Impact Offset		69,025	MWh	(105.42)	mills/kWh	($7,277)
System Usage Charge		69,025	MWh	(99.58)	mills/kWh	($6,874)
Energy Charge		69,025	MWh	68.66	mills/kWh	$4,739
Reactive Demand Charge		7,593	kVar	$0.50	kVar	$4
Subtotal with Consumer Impact Offset						$8,558
					w/o CIO	$15,834

PORTLAND GENERAL ELECTRIC
RATE DESIGN
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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	$598	655	Customers	$76.06	per cust, per mo.	$598
Three-Phase Secondary	$18,674	10,299	Customers	$151.11	per cust, per mo.	$18,675
Transmission & Related Service Charge	$5,974	8,221,335	kW demand	$0.73	per kW demand	$6,002
Distribution Charges						
Feeder Backbone	$18,541	10,087,730	kW faccap	$1.84	per kW faccap	$18,561
Feeder Local Facilities	$10,682	10,087,730	kW faccap	$1.06	per kW faccap	$10,693
Subtransmission Charge	$5,748	8,221,335	kW demand	$0.70	per kW demand	$5,755
Substation Charge	$10,658	8,221,335	kW demand	$1.30	per kW demand	$10,688
Secondary Franchise Fees & Other	$6,165	2,735,660	MWh	2.25	mills/kWh	$6,155
Secondary COS Energy Charge	$158,883	2,735,660	MWh	58.08	mills/kWh	$158,887
Subtotal	$235,923					$236,013
Pricing						
Functional Costs						
Basic Charge						
Secondary Single-Phase		655	Customers	$30.00	per cust, per mo.	$236
Secondary Three-Phase		10,299	Customers	$40.00	per cust, per mo.	$4,943
Trans. & Rel. Serv. Charge						
On-peak		8,206,049	kW demand	$0.84	per kW demand	$6,893
Off-peak		15,286	kW demand	$0.00	per kW demand	$0
Distribution Charges						
Secondary Facilities Charge						
First 30 kW		3,943,230	kW faccap	$2.96	<= 30 kW faccap	$11,672
Over 30 kW		6,144,500	kW faccap	$2.86	> 30 kW faccap	$17,573
Secondary Demand Charge						
On-peak		8,206,049	kW demand	$2.24	per kW demand	$18,382
Off-peak		15,286	kW demand	$0.00	per kW demand	$0
Secondary System Usage Charge Calc						
Franchise Fees & Other		2,735,660	MWh	2.25	mills/kWh	$6,155
Cust Impact Offset		2,735,660	MWh	0.48	mills/kWh	$1,313
Rate Design		2,735,660	MWh	3.99	mills/kWh	$10,915
System Usage Charge		2,735,660	MWh	6.72	mills/kWh	$18,384
COS Energy Charge						
On-peak		1,776,138	MWh	61.59	mills/kWh	$109,392
Off-peak		959,522	MWh	51.59	mills/kWh	$49,502
Reactive Demand Charge		505,048	kVar	$0.50	kVar	$253
Subtotal						$237,229
					w/o CIO	$235,916

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2015

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	$7,813	1,399	Customers	$465.34	per cust, per mo.	$7,813
Primary	$1,861	233	Customers	$666.14	per cust, per mo.	$1,861
Transmission & Related Service Charge	$6,300	7,873,918	kW on-peak	$0.80	per kW demand	$6,299
Distribution Charges						
Feeder Backbone	$20,060	10,907,116	kW faccap	$1.84	per kW faccap	$20,069
Feeder Local Facilities	$8,128	10,907,116	kW faccap	$0.75	per kW faccap	$8,180
Subtransmission Charge	$7,121	9,212,566	kW on-peak	$0.77	per kW on-peak demand	$7,094
Substation Charge	$13,203	9,212,566	kW on-peak	$1.43	per kW on-peak demand	$13,174
Secondary Franchise Fees & Other	$1,330	2,867,373	MWh	0.46	mills/kWh	$1,319
Primary Franchise Fees & Other	$255	866,706	MWh	0.29	mills/kWh	$251
COS Energy Charge	$172,763	3,077,124	MWh	56.14	mills/kWh	$172,750
Subtotal	$238,833					$238,811
Pricing						
Functional Costs						
Basic Charge						
Secondary		1,399	Customers	$470.00	per cust, per mo.	$7,891
Primary		233	Customers	$500.00	per cust, per mo.	$1,397
Secondary Trans. & Rel. Serv. Charge		6,296,454	kW on-peak	$0.84	per kW demand	$5,289
Primary Trans. & Rel. Serv. Charge		1,577,464	kW on-peak	$0.82	per kW demand	$1,294
Distribution Charges						
Secondary Facilities Charge						
First 200 kW		3,358,000	kW faccap	$3.09	per kW faccap	$10,376
Over 200 kW		5,173,935	kW faccap	$2.19	per kW faccap	$11,331
Primary Facilities Charge						
First 200 kW		558,800	kW faccap	$3.04	per kW faccap	$1,699
Over 200 kW		1,816,381	kW faccap	$2.14	per kW faccap	$3,887
Secondary Demand Charge		7,190,982	kW on-peak	$2.24	per kW demand	$16,108
Primary Demand Charge		2,021,584	kW on-peak	$2.20	per kW demand	$4,447
Secondary System Usage Charge Calc						
COS Franchise Fees & Other		2,431,372	MWh	0.66	mills/kWh	$1,605
Cust Impact Offset		2,431,372	MWh	0.48	mills/kWh	$1,167
COS System Usage Charge		2,431,372	MWh	1.14	mills/kWh	$2,772
DA Franchise Fees & Other		436,001	MWh	(0.64)	mills/kWh	($279)
Cust Impact Offset		436,001	MWh	0.48	mills/kWh	$209
DA System Usage Charge		436,001	MWh	(0.16)	mills/kWh	($70)
Primary System Usage Charge Calc						
COS Franchise Fees & Other		645,752	MWh	0.62	mills/kWh	$400
Cust Impact Offset		645,752	MWh	0.48	mills/kWh	$310
COS System Usage Charge		645,752	MWh	1.10	mills/kWh	$710
DA Franchise Fees & Other		220,953	MWh	(0.65)	mills/kWh	($144)
Cust Impact Offset		220,953	MWh	0.48	mills/kWh	$106
DA System Usage Charge		220,953	MWh	(0.17)	mills/kWh	($38)
Secondary COS Energy Charge						
On-peak		1,598,200	MWh	59.85	mills/kWh	$95,652
Off-peak		833,171	MWh	49.85	mills/kWh	$41,534
Primary COS Energy Charge						
On-peak		406,710	MWh	58.81	mills/kWh	$23,919
Off-peak		239,043	MWh	48.81	mills/kWh	$11,668
Reactive Demand Charge		1,575,849	kVar	$0.50	kVar	$788
Subtotal						$240,654
					w/o CIO	$238,862

PORTLAND GENERAL ELECTRIC
RATE DESIGN
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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	$131	1	Customers	$10,880.57	per cust, per mo.	$131
Primary Basic Charge	$3,154	27	Customers	$9,734.66	per cust, per mo.	$3,154
Subtransmission Basic Charge	$1,074	8	Customers	$11,190.08	per cust, per mo.	$1,074
Transmission & Related Service Charge	$1,996	2,042,795	kW on-peak	$0.98	per kW on-peak demand	$2,002
Distribution Charges						
Feeder Backbone	$4,189	4,501,188	kW faccap	$0.93	per kW faccap	$4,186
Feeder Local Facilities						$0
Subtransmission Demand Charge	$3,359	3,482,292	kW on-peak	$0.96	per kW on-peak demand	$3,343
Substation Demand Charge	$3,905	2,455,436	kW on-peak	$1.59	per kW on-peak demand	$3,904
Secondary Franchise Fees & Other	($12)	14,864	MWh	(0.84)	mills/kWh	($12)
Primary Franchise Fees & Other	($117)	1,420,271	MWh	(0.08)	mills/kWh	($114)
Subtransmission Franchise Fees & Other	($218)	859,043	MWh	(0.25)	mills/kWh	($215)
Energy Charge	$58,445	1,123,738	MWh	52.01	mills/kWh	$58,446
Subtotal	$75,906					$75,899
Pricing						
Functional Costs						
Secondary Basic Charge		1	Customers	$5,440.00	per cust, per mo.	$65
Primary Basic Charge		27	Customers	$4,870.00	per cust, per mo.	$1,578
Subtransmission Basic Charge		8	Customers	$5,600.00	per cust, per mo.	$538
Secondary Trans. & Rel. Serv. Charge		0	kW on-peak	$0.84	per kW on-peak demand	$0
Primary Trans. & Rel. Serv. Charge		1,585,480	kW on-peak	$0.82	per kW on-peak demand	$1,300
Subtransmission Trans. & Rel. Serv. Charge		457,315	kW on-peak	$0.81	per kW on-peak demand	$370
Distribution Charges						
Secondary Facilities Charge						
First 1,000 kW		12,000	kW faccap	$1.97	per kW faccap	$24
1,001-4,000 kW		36,000	kW faccap	$1.97	per kW faccap	$71
Greater than 4,000 kW		53,112	kW faccap	$1.50	per kW faccap	$80
Primary Facilities Charge						
First 1,000 kW		324,000	kW faccap	$1.94	per kW faccap	$629
1,001-4,000 kW		972,000	kW faccap	$1.94	per kW faccap	$1,886
Greater than 4,000 kW		1,309,032	kW faccap	$1.47	per kW faccap	$1,924
Subtransmission Facilities Charge						
First 1,000 kW		96,000	kW faccap	$1.94	per kW faccap	$186
1,001-4,000 kW		288,000	kW faccap	$1.94	per kW faccap	$559
Greater than 4,000 kW		1,411,044	kW faccap	$1.47	per kW faccap	$2,074
Secondary Demand Charge		41,710	kW on-peak	$2.24	per kW on-peak demand	$93
Primary Demand Charge		2,413,726	kW on-peak	$2.20	per kW on-peak demand	$5,310
Subtransmission Demand Charge		1,026,856	kW on-peak	$0.83	per kW on-peak demand	$852
Secondary System Usage Charge Calc						
COS Franchise Fees & Other		0	MWh	0.37	mills/kWh	$0
Cust Impact Offset		0	MWh	0.48	mills/kWh	$0
COS System Usage Charge		0	MWh	0.85	mills/kWh	$0
DA Franchise Fees & Other		14,864	MWh	(0.84)	mills/kWh	($12)
Cust Impact Offset		14,864	MWh	0.48	mills/kWh	$7
DA System Usage Charge		14,864	MWh	(0.36)	mills/kWh	($5)
Primary System Usage Charge Calc						
COS Franchise Fees & Other		913,928	MWh	0.34	mills/kWh	$311
Cust Impact Offset		913,928	MWh	0.48	mills/kWh	$439
COS System Usage Charge		913,928	MWh	0.82	mills/kWh	$749
DA Franchise Fees & Other		506,343	MWh	(0.84)	mills/kWh	($425)
Cust Impact Offset		506,343	MWh	0.48	mills/kWh	$243
DA System Usage Charge		506,343	MWh	(0.36)	mills/kWh	($182)
Subtransmission System Usage Charge Calc						
COS Franchise Fees & Other		209,810	MWh	0.32	mills/kWh	$67
Cust Impact Offset		209,810	MWh	0.48	mills/kWh	$101
COS System Usage Charge		209,810	MWh	0.80	mills/kWh	$168
DA Franchise Fees & Other		333,091	MWh	(0.85)	mills/kWh	($283)
Cust Impact Offset		333,091	MWh	0.48	mills/kWh	$160
DA System Usage Charge		333,091	MWh	(0.37)	mills/kWh	($123)
Secondary Energy Charge						
On-peak		0	MWh	57.25	mills/kWh	$0
Off-peak		0	MWh	47.25	mills/kWh	$0
Primary Energy Charge						
On-peak		534,213	MWh	56.29	mills/kWh	$30,071
Off-peak		379,714	MWh	46.29	mills/kWh	$17,577
Subtransmission Energy Charge						
On-peak		124,041	MWh	55.57	mills/kWh	$6,893
Off-peak		85,769	MWh	45.57	mills/kWh	$3,908
Reactive Demand Charge		497,315	kVar	$0.50	kVar	$249
Subtotal						$76,843
					w/o CIO	$75,894

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2015

Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULE 90						
Primary Voltage Service						
Allocations						
Functional Costs						
Primary Basic Charge	$415	4	Customers	$8,656.05	per cust, per mo.	$415
Transmission & Related Service Charge	$2,587	2,171,902	kW on-peak	$1.19	per kW on-peak demand	$2,585
Distribution Charges						
Feeder Backbone	$1,451	2,311,315	kW faccap	$0.63	per kW faccap	$1,456
Subtransmission Demand Charge	$2,049	2,171,902	kW on-peak	$0.94	per kW on-peak demand	$2,042
Substation Demand Charge	$3,800	2,171,902	kW on-peak	$1.75	per kW on-peak demand	$3,801
Primary Franchise Fees & Other	$340	1,453,535	MWh	0.23	mills/kWh	$334
Energy Charge	$73,605	1,453,535	MWh	50.64	mills/kWh	$73,607
Subtotal	$84,247					$84,240
Pricing						
Functional Costs						
Primary Basic Charge		4	Customers	$25,000.00	per cust, per mo.	$1,200
Primary Trans. & Rel. Serv. Charge		2,171,902	kW on-peak	$0.82	per kW on-peak demand	$1,781
Distribution Charges						
Primary Facilities Charge		2,311,315	kW faccap	$1.08	per kW faccap	$2,496
Primary Demand Charge		2,171,902	kW on-peak	$2.20	per kW on-peak demand	$4,778
Primary System Usage Charge Calc						
COS Franchise Fees & Other		1,453,535	MWh	0.23	mills/kWh	$334
Cust Impact Offset		1,453,535	MWh	0.48	mills/kWh	$698
COS System Usage Charge		1,453,535	MWh	0.71	mills/kWh	$1,032
Primary Energy Charge						
On-peak		836,449	MWh	54.88	mills/kWh	$45,904
Off-peak		617,086	MWh	44.88	mills/kWh	$27,695
Reactive Demand Charge		96,939	kVar	$0.50	kVar	$48
						$84,935
					w/o CIO	$84,237

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2015

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	$1,874	205	Customers	$761.75	per cust, per mo.	$1,874
Trans. & Rel. Serv. Charge	$171	97,094	MWh	1.76	mills/kWh	$171
Distribution Charge	$2,162	97,094	MWh	22.27	mills/kWh	$2,162
Franchise Fees & Other	$437	97,094	MWh	4.50	mills/kWh	$437
COS Energy Charge	$4,821	97,094	MWh	49.66	mills/kWh	$4,822
Fixed Charges	$7,796					$7,796
Subtotal	$17,260					$17,261
Pricing						
Functional Costs						
Trans. & Rel. Serv. Charge		97,094	MWh	1.76	mills/kWh	$171
Distribution Charge		97,094	MWh	41.57	mills/kWh	$4,036
System Usage Charge Calc						
Franchise Fees & Other		97,094	MWh	4.50	mills/kWh	$437
Cust Impact Offset		97,094	MWh	1.74	mills/kWh	$169
System Usage Charge		97,094	MWh	6.24	mills/kWh	$606
COS Energy Charge		97,094	MWh	49.66	mills/kWh	$4,822
Fixed Charges		97,094	MWh			$7,796
Subtotal						$17,430
					w/o CIO	$17,261
SCHEDULE 92						
Traffic Signals						
Allocations						
Functional Costs						
Basic Charge	$33	17	Customers	$160.04	per cust, per mo.	$33
Trans. & Rel. Serv. Charge	$6	3,327	MWh	1.75	mills/kWh	$6
Distribution Charge	$30	3,327	MWh	8.88	mills/kWh	$30
Franchise Fees & Other	$6	3,327	MWh	1.93	mills/kWh	$6
COS Energy Charge	$173	3,327	MWh	51.94	mills/kWh	$173
Subtotal	$247					$247
Pricing						
Functional Costs						
Trans. & Rel. Serv. Charge		3,327	MWh	1.75	mills/kWh	$6
Distribution Charge		3,327	MWh	18.69	mills/kWh	$62
System Usage Charge Calc						
Franchise Fees & Other		3,327	MWh	1.93	mills/kWh	$6
Cust Impact Offset		3,327	MWh	0.48	mills/kWh	$2
System Usage Charge		3,327	MWh	2.41	mills/kWh	$8
COS Energy Charge		3,327	MWh	51.94	mills/kWh	$173
Subtotal						$249
					w/o CIO	$247

PORTLAND GENERAL ELECTRIC
CONSUMER IMPACT OFFSET

Grouping	Cycle MWH	Revenues at 2014 Prices ($000)	2015 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	7,462,740	$868,513	$879,952	1.3%	12.0%	$0	0	$3,562	0.48	$3,582
Schedule 15	15,972	$3,612	$3,751	3.9%	12.0%				(10.58)	($169)
Schedule 32	1,556,500	$167,877	$168,185	0.2%	12.0%	$0	0	$743	0.48	$747
Schedule 38	43,599	$5,536	$5,715	3.2%	12.0%	$0	0	$21	0.48	$21
Schedule 47	18,147	$2,918	$5,046	72.9%	12.0%	($1,778)	(18,147)		(97.97)	($1,778)
Schedule 49	69,025	$7,641	$15,835	107.2%	12.0%	($7,276)	(69,025)		(105.42)	($7,277)
Schedule 83	2,735,660	$237,385	$235,923	-0.6%	12.0%	$0	0	$1,306	0.48	$1,313
Schedule 85	3,077,124	$248,730	$244,798.57	-1.6%	12.0%	$0	0	$1,469	0.48	$1,477
Schedule 89	1,123,738	$83,054.51	$80,949.36	-2.5%	12.0%	$0	0	$536	0.48	$539
Schedule 90	1,453,535	$86,273	$84,247	-2.3%	12.0%	$0	0	$694	0.48	$698
Schedules 91 & 95	97,094	$17,403	$17,260	-0.8%	12.0%				1.74	$169
Schedule 92	3,327	$251	$247	-1.6%	12.0%	$0	0	$2	0.48	$2
COS TOTALS	17,656,462									
Sch 485 Energy	656,955							$314	0.48	$315
Sch 489 Energy	854,299							$408	0.48	$410
Totals	19,167,715	$1,729,193	$1,741,909	0.7%		($9,054)	(87,173)	$9,054		$50

Cap on Rate Change	12.0%
Cap on CIO (mills/kWh)	(130.00)

Note: does not include Sch 76R
Note: does not include employee discount

PORTLAND GENERAL ELECTRIC
2015 Test Period Functionalized Revenue Requirement

Function	Amount	Spread
PRODUCTION	$1,035,643	$1,035,643
TRANSMISSION	$35,360	$35,360
ANCILLARY	$4,900	$4,900
DISTRIBUTION	$551,315	$551,315
METERING	$2,515	$2,515
BILLING	$57,454	$57,454
CONSUMER	$55,313	$55,313
TOTALS	$1,742,500	$1,742,500
Schedule 129		($11,009)
Employee Discount		$900
Partial Requirements Transmission		($407)
Partial Requirements Distribution		($407)
Spread Total		$1,731,576

Note: Employee discount is allocated to distribution

PORTLAND GENERAL ELECTRIC
UNBUNDLED 2015 COSTS ($000)

	Unbundled Costs	Adjusted to Cycle
Fixed Generation Revenue Requirement	$442,218	$442,031
Net Variable Power Costs	$593,425	$593,174
Production Costs	$1,035,643	$1,035,206
Ancillary Services	$4,900	$4,898
Transmission	$34,953	$34,939
Distribution Services	$551,315	
Franchise	($43,583)	
Uncollectibles	($8,712)	
Trojan Decommissioning	($3,500)	
Partial Requirements Daily Demand	($407)	
Employee Discount	$900	$900
Distribution Costs	$496,012	$495,843
Consumer Services		
Metering Services	$2,515	$2,514
Billing Services	$57,454	$57,434
Other Consumer Services	$55,313	$55,295
Franchise Fees	$43,583	$43,568
Uncollectibles	$8,712	$8,710
Trojan Decommissioning	$3,500	$3,499
Schedule 129	($11,009)	($11,009)
Totals	$1,731,576	$1,730,895
Net of employee discount	$1,730,676	$1,729,995
Net of Sch 129	$1,741,685	$1,741,004
Calendar MWH	19,490,502	
Cycle MWH	19,483,857	
Cycle/Cal Ratio	99.97%	
COS Calendar Energy MWH	17,663,507	
COS Cycle MWH	17,656,462	
Cycle/Cal Ratio	99.96%	

PORTLAND GENERAL ELECTRIC
ALLOCATION OF PRODUCTION COSTS TO COS CUSTOMERS
2015

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	7,458,711	$419,841	50.61%	$167,981	$587,822	44.96%	$465,597	$465,849
Schedule 15	15,972	$788	0.06%	$212	$1,000	0.08%	$792	$792
Schedule 32	1,559,890	$86,120	8.55%	$28,376	$114,496	8.76%	$90,689	$90,492
Schedule 38	43,566	$2,487	0.21%	$708	$3,195	0.24%	$2,531	$2,533
Schedule 47	18,252	$1,042	0.19%	$625	$1,667	0.13%	$1,321	$1,313
Schedule 49	69,104	$3,897	0.63%	$2,084	$5,982	0.46%	$4,738	$4,733
Schedule 83	2,744,338	$152,588	14.57%	$48,350	$200,938	15.37%	$159,157	$158,654
Schedule 85	2,197,683	$120,889	10.82%	$35,924	$156,814	11.99%	$124,208	$122,357
Schedule 85 1-4 MW	876,618	$47,466	4.03%	$13,388	$60,854	4.65%	$48,201	$50,157
Schedule 89 GT 4 MW	1,112,629	$58,483	4.36%	$14,470	$72,953	5.58%	$57,784	$58,361
Schedule 90	1,466,333	$77,033	5.56%	$18,463	$95,496	7.30%	$75,639	$74,979
Schedule 91/95	97,094	$4,788	0.39%	$1,290	$6,078	0.46%	$4,814	$4,814
Schedule 92	3,319	$177	0.01%	$41	$217	0.02%	$172	$173
TOTAL	17,663,507	$975,598	100.0%	$331,913	$1,307,511	100.00%	$1,035,643	$1,035,206
Simple Cycle Proxy Plant $/kW				$100.20		**TARGET**	**$1,035,643**	
Projected Peak Load				3,313				
Marginal Capacity Costs ($000)				$331,913				

PORTLAND GENERAL ELECTRIC
Marginal Energy Costs: 2015 Test Period

Schedules	Marginal Energy Cost	Energy Percent
Schedule 7	$419,840,573	43.03%
Schedule 15	$787,636	0.08%
Schedule 32	$86,120,231	8.83%
Schedule 38	$2,486,765	0.25%
Schedule 47	$1,042,147	0.11%
Schedule 49	$3,897,406	0.40%
Schedule 83	$152,587,547	15.64%
Schedule 85	$120,889,319	12.39%
Schedule 85 1-4 MW	$47,466,348	4.87%
Schedule 89 GT 4 MW	$58,482,927	5.99%
Schedule 90	$77,032,786	7.90%
Schedule 91/95	$4,788,047	0.49%
Schedule 92	$176,735	0.02%
TOTAL	$975,598,466	100.00%

PORTLAND GENERAL ELECTRIC
ALLOCATION OF TRANSMISSION REVENUE REQUIREMENT
2015

Schedules	Transmission Allocation Percent	Class Revenue Requirement
Schedule 7	47.96%	$16,756
Schedule 15	0.07%	$24
Schedule 32	8.65%	$3,021
Schedule 38	0.23%	$80
Schedule 47	0.16%	$56
Schedule 49	0.55%	$191
Schedule 83	14.94%	$5,221
Schedule 85	11.37%	$3,973
Schedule 85 1-4 MW	4.32%	$1,511
Schedule 89 GT 4 MW	4.93%	$1,723
Schedule 90-P	6.38%	$2,229
Schedules 91/95	0.42%	$148
Schedule 92	0.01%	$5
Target	100.00%	$34,939

Capacity Allocation	65%
Energy Allocation	35%

PORTLAND GENERAL ELECTRIC
ALLOCATION OF ANCILLARY SERVICE COSTS
2015

Schedules	Production Allocation Percent	Class Revenue Requirement
Schedule 7	44.96%	$2,202
Schedule 15	0.08%	$4
Schedule 32	8.76%	$429
Schedule 38	0.24%	$12
Schedule 47	0.13%	$6
Schedule 49	0.46%	$22
Schedule 83	15.37%	$753
Schedule 85	11.99%	$587
Schedule 85 1-4 MW	4.65%	$228
Schedule 89 GT 4 MW	5.58%	$273
Schedule 90-P	7.30%	$358
Schedules 91/95	0.46%	$23
Schedule 92	0.02%	$1
TOTAL	100.00%	$4,898
	TARGET	$4,898

PORTLAND GENERAL ELECTRIC
Applicable 2015 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	2,960	$149.89	$443,667
	SCHEDULE 2 - REACTIVE SUPPLY & VOLTAGE CONTROL		$/kW year	
2	12 CP kW Average	2,959,950	$0.461	$1,364,537
	SCHEDULE 3 - REGULATION & FREQUENCY RESPONSE		$/kW month	
3	Billing Determinant: Sum of Monthly Average 12 CP KW	35,519,400	$0.09	$3,091,431
	Charge: $6.695 per kW per month x .013			
4			**ANCILLARY SERVICES TOTAL**	$4,899,635

PORTLAND GENERAL ELECTRIC
ALLOCATION OF TROJAN DECOMMISSIONING COSTS
2015

Schedules	Cycle Generation Revenues	Allocation Percent	Class Revenue Requirement
Schedule 7	$466,645,372	41.80%	$1,463
Schedule 15	$793,170	0.07%	$2
Schedule 32	$90,666,145	8.12%	$284
Schedule 38	$2,536,111	0.23%	$8
Schedule 47	$1,314,949	0.12%	$4
Schedule 49	$4,739,282	0.42%	$15
Schedule 83	$158,894,086	14.23%	$498
Schedule 85-S	$132,587,086	11.88%	$416
Schedule 85-S 1-4 MW	$29,073,446	2.60%	$91
Schedule 89-S GT 4 MW	$793,383	0.07%	$2
Schedule 85-P	$15,402,420	1.38%	$48
Schedule 85-P 1-4 MW	$32,348,928	2.90%	$101
Schedule 89-P GT 4 MW	$74,065,363	6.63%	$232
Schedule 89-T	$27,888,888	2.50%	$87
Schedule 90-P	$73,599,119	6.59%	$231
Schedule 91/95	$4,821,688	0.43%	$15
Schedule 92	$172,804	0.02%	$1
TOTAL	$1,116,342,241		$3,499
		TARGET	$3,499

PORTLAND GENERAL ELECTRIC
ALLOCATION OF FRANCHISE FEES
2015

Schedules	Distribution Allocations	Transmission Allocations	Generation Allocations	Schedule 129 Allocations	Subtotal Allocations	Distribution Fran. Fee Allocations	Transmission Fran. Fee Allocations	Generation Fran. Fee Allocations	Schedule 129 Fran. Fee Allocations	Total Fran. Fee Allocations
Schedule 7	$373,193	$18,958	$466,521		$858,672	$9,512	$483	$11,891	$0	$21,886
Schedule 15	$2,837	$28	$793		$3,659	$72	$1	$20	$0	$93
Schedule 32	$70,048	$3,450	$90,623		$164,120	$1,785	$88	$2,310	$0	$4,183
Schedule 38	$2,948	$92	$2,536		$5,576	$75	$2	$65	$0	$142
Schedule 47	$3,545	$62	$1,315		$4,922	$90	$2	$34	$0	$125
Schedule 49	$10,493	$214	$4,740		$15,447	$267	$5	$121	$0	$394
Schedule 83-S	$65,399	$5,974	$158,883		$230,255	$1,667	$152	$4,050	$0	$5,869
Schedule 85 201-4,000 kW	$58,841	$6,300	$172,763	$5,966	$243,870	$1,500	$161	$4,403	$152	$6,216
Schedule 89 GT 4 MW	$16,134	$1,996	$58,445	$5,044	$81,619	$411	$51	$1,490	$129	$2,080
Schedule 90-P	$7,946	$2,587	$73,605		$84,138	$203	$66	$1,876	$0	$2,145
Schedules 91/95	$11,847	$171	$4,821		$16,839	$302	$4	$123	$0	$429
Schedule 92	$63	$6	$173		$241	$2	$0	$4	$0	$6
TOTALS	$623,294	$39,836	$1,035,218	$11,009	$1,709,358	$15,886	$1,015	$26,385	$281	$43,568

Franchise Fee Revenue Requirement **$43,568**

Schedules	Distribution MWh	Distribution mills/kWh	Transmission MWh	Transmission mills/kWh	Generation MWh	Generation mills/kWh	Schedule 129 MWh	Schedule 129 mills/kWh	Total COS mills/kWh	Total DA mills/kWh
Schedule 7	7,462,740	1.27	7,462,740	0.06	7,462,740	1.59	0		2.93	
Schedule 15	15,972	4.53	15,972	0.04	15,972	1.27	0		5.84	4.53
Schedule 32	1,556,500	1.15	1,556,500	0.06	1,556,500	1.48	0		2.69	1.15
Schedule 38	43,599	1.72	43,599	0.05	43,599	1.48	0		3.26	1.72
Schedule 47	18,147	4.98	18,147	0.09	18,147	1.85	0		6.91	
Schedule 49	69,025	3.87	69,025	0.08	69,025	1.75	0		5.70	3.87
Schedule 83-S	2,735,660	0.61	2,735,660	0.06	2,735,660	1.48	0		2.15	0.61
Schedule 85-S 201-4,000 kW	2,867,373	0.40	2,431,372	0.05	2,431,372	1.44	436,001	0.19	1.89	0.59
Schedule 89-S GT 4 MW	14,864	0.21	0	0.05	0	1.36	14,864	0.19	1.61	0.40
Schedule 85-P 201-4,000 kW	866,706	0.39	645,752	0.05	645,752	1.41	220,953	0.19	1.85	0.58
Schedule 89-P GT 4 MW	1,420,271	0.21	913,928	0.05	913,928	1.33	506,343	0.19	1.58	0.40
Schedule 89-T	542,901	0.20	209,810	0.05	209,810	1.32	333,091	0.19	1.56	0.39
Schedule 90-P	1,453,535	0.14	1,453,535	0.05	1,453,535	1.29			1.48	0.33
Schedule 91/95	97,094	3.11	97,094	0.04	97,094	1.27	0		4.42	3.11
Schedule 92	3,327	0.48	3,327	0.04	3,327	1.32	0		1.85	0.48
TOTALS	19,167,715		17,656,462		17,656,462		1,511,253			

Revenues

Schedules	MWh	Fran. Fee mills/kWh	Fran. Fee Revenues
Schedule 7	7,462,740	2.93	$21,866
Schedule 15	15,972	5.84	$93
Schedule 32	1,556,500	2.69	$4,187
Schedule 38	43,599	3.26	$142
Schedule 47	18,147	6.91	$125
Schedule 49	69,025	5.70	$393
Schedule 83-S	2,735,660	2.15	$5,882
Schedule 85-S 201-4,000 kW	2,431,372	1.89	$4,595
Schedule 485-S 201-4,000 kW	436,001	0.59	$257
Schedule 89-S GT 4 MW	0	1.61	$0
Schedule 489-S GT 4 MW	14,864	0.40	$6
Schedule 85-P 201-4,000 kW	645,752	1.85	$1,195
Schedule 485-P 201-4,000 kW	220,953	0.58	$128
Schedule 89-P GT 4 MW	913,928	1.58	$1,444
Schedule 489-P GT 4 MW	506,343	0.40	$203
Schedule 89-T	209,810	1.56	$327
Schedule 489-T	333,091	0.39	$130
Schedule 90-P	1,453,535	1.48	$2,151
Schedule 91/95	97,094	4.42	$429
Schedule 92	3,327	1.85	$6
TOTALS	19,167,715		$43,560

PORTLAND GENERAL ELECTRIC
ALLOCATION OF SCHEDULE 129 TRANSITION ADJUSTMENT
2015

Schedules	Cycle Energy	Percent	Allocations ($000)
Schedule 85-S	2,350,776	32.8%	($3,119)
Schedule 85-S 1-4 MW	516,597	7.2%	($685)
Schedule 89-S GT 4 MW	14,864	0.2%	($20)
Schedule 85-P	279,292	3.9%	($371)
Schedule 85-P 1-4 MW	587,413	8.2%	($779)
Schedule 89-P GT 4 MW	1,420,271	19.8%	($1,884)
Schedule 90-P	1,453,535	20.3%	($1,928)
Schedule 89-T	542,901	7.6%	($720)
TOTAL	7,165,650	100.00%	($9,507)
		TARGET	($9,507)

ALLOCATION OF TRANSITION ADJUSTMENT FOR POST 2013 VINTAGE CUSTOMERS

Schedules	Cycle Energy	Percent	Allocations ($000)
Schedule 7	7,462,740	38.9%	($585)
Schedule 15	15,972	0.1%	($1)
Schedule 32	1,556,500	8.1%	($122)
Schedule 38	43,599	0.2%	($3)
Schedule 47	18,147	0.1%	($1)
Schedule 49	69,025	0.4%	($5)
Schedule 83	2,735,660	14.3%	($214)
Schedule 85-S	2,350,776	12.3%	($184)
Schedule 85-S 1-4 MW	516,597	2.7%	($40)
Schedule 89-S GT 4 MW	14,864	0.1%	($1)
Schedule 85-P	279,292	1.5%	($22)
Schedule 85-P 1-4 MW	587,413	3.1%	($46)
Schedule 89 GT 4 MW	1,420,271	7.4%	($111)
Schedule 89-T	542,901	2.8%	($43)
Schedule 90-P	1,453,535	7.6%	($114)
Schedules 91/95	97,094	0.5%	($8)
Schedule 92	3,327	0.0%	($0)
TOTAL	19,167,715	100.00%	($1,503)
		TARGET	($1,503)

Note: does not include partial requirements customers

PORTLAND GENERAL ELECTRIC
ALLOCATION OF UNCOLLECTIBLES
2015

Grouping	Marginal Cost Allocation Percent	Class Revenue Requirement
Schedule 7		
Single Phase	86.27%	$7,514
Three Phase	0.01%	$1
Schedule 15		
Residential	0.11%	$10
Commercial	0.17%	$15
Schedule 32		
Single Phase	2.98%	$259
Three Phase	1.93%	$168
Schedule 38		
Single Phase	0.00%	$0
Three Phase	0.01%	$1
Schedule 47		
Single Phase	0.01%	$1
Three Phase	0.10%	$9
Schedule 49		
Single Phase	0.00%	$0
Three Phase	0.24%	$21
Schedule 83		
Single Phase	0.13%	$11
Three Phase	1.98%	$173
Schedule 85		
Secondary	0.41%	$36
Primary	0.05%	$4
Schedule 85 1-4 MW		
Secondary	0.12%	$11
Primary	0.13%	$11
Schedule 89 GT 4 MW		
Secondary	0.15%	$13
Primary	4.01%	$349
Subtransmission	1.19%	$104
Schedule 90-P	0.00%	$0
Schedules 91/95	0.00%	$0
Schedule 92	0.00%	$0
TOTAL	100.00%	$8,710
	TARGET	$8,710

PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION COST
2015

Grouping			Usages	Units & Basis	Marginal Unit Cost	Marginal Cost Revenues	Class Revenue Requirement
Schedule 7 Residential							
CUSTOMER	Meters						
		Single-Phase Customers	739,963	Customers	$20.41	$15,103	$20,742
		Three-Phase Customers	85	Customers	$55.98	$5	$7
	Service & Transformer						
		Single-Phase Customers	739,963	Customers	$70.70	$52,315	$71,851
		Three-Phase Customers	85	Customers	$132.84	$11	$16
FACILITIES	Feeder Backbone						
		Single-Phase Customers	1,887,723	kW, rateclass peak	$23.78	$44,890	$61,653
		Three-Phase Customers	218	kW, rateclass peak	$23.78	$5	$7
	Feeder Local Facilities						
		Single-Phase Customers	2,959,854	Design Demand	$16.07	$47,565	$65,326
		Three-Phase Customers	342	Design Demand	$16.07	$5	$8
DEMAND	Subtransmission		1,915,316	kW, rateclass peak	$7.31	$14,001	$19,229
	Substation		1,887,941	kW, rateclass peak	$13.75	$25,959	$35,653
SUBTOTAL						$199,860	$274,491
Schedule 15 Residential Outdoor Area Lighting							
CUSTOMER	Customer Service		9,374	Lights	$3.28	$31	$42
	Transformer		9,374	Lights	$5.45	$51	$70
FACILITIES	Feeder Backbone		958	kW, rateclass peak	$24.65	$24	$32
	Feeder Local Facilities		958	Design Demand	$16.75	$16	$22
DEMAND	Subtransmission		972	kW, rateclass peak	$7.31	$7	$10
	Substation		958	kW, rateclass peak	$13.75	$13	$18
FIXED	Luminaires & Poles						$462
SUBTOTAL						$142	$657
Schedule 15 Commercial Outdoor Area Lighting							
CUSTOMER	Customer Service		10,946	Lights	$3.28	$36	$49
	Transformer		10,946	Lights	$5.45	$60	$82
FACILITIES	Feeeder Backbone		3,181	kW, rateclass peak	$24.65	$78	$108
	Feeder Local Facilities		3,181	Design Demand	$16.75	$53	$73
DEMAND	Subtransmission		3,227	kW, rateclass peak	$7.31	$24	$32
	Substation		3,181	kW, rateclass peak	$13.75	$44	$60
FIXED	Luminaires & Poles						$1,535
SUBTOTAL						$295	$1,939
Schedule 15 Outdoor Area Lighting							
CUSTOMER	Customer Service						$91
	Transformer						$152
FACILITIES	Feeeder Backbone						$140
	Feeder Local Facilities						$95
DEMAND	Subtransmission						$42
	Substation						$78
FIXED	Luminaires & Poles						$1,997
SUBTOTAL							$2,596

PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION COST
2015

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	54,240	Customers	$17.21	$933	$1,282
		Three-Phase Customers	35,231	Customers	$68.38	$2,409	$3,309
	Service & Transformer						
		Single-Phase Customers	54,240	Customers	$101.80	$5,522	$7,584
		Three-Phase Customers	35,231	Customers	$220.15	$7,756	$10,652
FACILITIES	Feeder Backbone						
		Single-Phase Customers	126,853	kW, rateclass peak	$27.38	$3,473	$4,770
		Three-Phase Customers	193,936	kW, rateclass peak	$27.38	$5,310	$7,293
	Feeder Local Facilities						
		Single-Phase Customers	271,202	Design Demand	$23.44	$6,357	$8,731
		Three-Phase Customers	422,769	Design Demand	$9.36	$3,957	$5,435
DEMAND	Subtransmission		325,441	kW, rateclass peak	$7.31	$2,379	$3,267
	Substation		320,789	kW, rateclass peak	$13.75	$4,411	$6,058
SUBTOTAL						$42,507	$58,380
Schedule 38 General Service							
CUSTOMER	Meters						
		Single-Phase Customers	51	Customers	$51.03	$3	$4
		Three-Phase Customers	510	Customers	$120.77	$62	$85
	Service & Transformer						
		Single-Phase Customers	51	Customers	$193.91	$10	$14
		Three-Phase Customers	510	Customers	$526.06	$268	$368
FACILITIES	Feeder Backbone						
		Single-Phase Customers	720	kW, rateclass peak	$33.20	$24	$33
		Three-Phase Customers	19,527	kW, rateclass peak	$33.20	$648	$890
	Feeder Local Facilities						
		Single-Phase Customers	1,841	Design Demand	$19.24	$35	$49
		Three-Phase Customers	43,292	Design Demand	$13.38	$579	$796
DEMAND	Subtransmission		20,540	kW, rateclass peak	$7.31	$150	$206
	Substation		20,247	kW, rateclass peak	$13.75	$278	$382
SUBTOTAL						$2,058	$2,826
Schedule 47 Irrigation & Drainage Service - < 30 kW							
CUSTOMER	Meters						
		Single-Phase Customers	208	Customers	$55.55	$12	$16
		Three-Phase Customers	2,783	Customers	$81.68	$227	$312
	Service & Transformer						
		Single-Phase Customers	208	Customers	$7.81	$2	$2
		Three-Phase Customers	2,783	Customers	$17.45	$49	$67
FACILITIES	Feeder Backbone						
		Single-Phase Customers	455	kW, rateclass peak	$69.29	$31	$43
		Three-Phase Customers	13,595	kW, rateclass peak	$69.29	$942	$1,294
	Feeder Local Facilities						
		Single-Phase Customers	2,080	Design Demand	$49.24	$102	$141
		Three-Phase Customers	27,832	Design Demand	$25.31	$704	$967
DEMAND	Subtransmission		14,254	kW, rateclass peak	$7.31	$104	$143
	Substation		14,050	kW, rateclass peak	$13.75	$193	$265
SUBTOTAL						$2,367	$3,251

PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION COST
2015

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	3	Customers	$57.97	$0	$0
		Three-Phase Customers	1,326	Customers	$66.46	$88	$121
	Service & Transformer						
		Single-Phase Customers	3	Customers	$136.12	$0	$1
		Three-Phase Customers	1,326	Customers	$143.01	$190	$260
FACILITIES	Feeder Backbone						
		Single-Phase Customers	114	kW, rateclass peak	$71.27	$8	$11
		Three-Phase Customers	53,082	kW, rateclass peak	$71.27	$3,783	$5,196
	Feeder Local Facilities						
		Single-Phase Customers	153	Design Demand	$32.54	$5	$7
		Three-Phase Customers	90,831	Design Demand	$25.37	$2,304	$3,165
DEMAND	Subtransmission		53,968	kW, rateclass peak	$7.31	$395	$542
	Substation		53,196	kW, rateclass peak	$13.75	$731	$1,005
SUBTOTAL						$7,505	$10,307
Schedule 83 General Service (31-200 kW)							
CUSTOMER	Meters						
		Single-Phase Customers	655	Customers	$49.85	$33	$45
		Three-Phase Customers	10,299	Customers	$110.53	$1,138	$1,563
	Service & Transformer						
		Single-Phase Customers	655	Customers	$327.25	$214	$294
		Three-Phase Customers	10,299	Customers	$922.30	$9,498	$13,045
FACILITIES	Feeder Backbone						
		Single-Phase Customers	17,621	kW, rateclass peak	$23.92	$421	$579
		Three-Phase Customers	546,749	kW, rateclass peak	$23.92	$13,078	$17,962
	Feeder Local Facilities						
		Single-Phase Customers	26,259	Design Demand	$19.79	$520	$714
		Three-Phase Customers	814,618	Design Demand	$8.91	$7,258	$9,969
DEMAND	Subtransmission		572,553	kW, rateclass peak	$7.31	$4,185	$5,748
	Substation		564,370	kW, rateclass peak	$13.75	$7,760	$10,658
SUBTOTAL						$44,107	$60,577
Schedule 85 General Service (201-1,000 kW)							
CUSTOMER	Meters						
		Secondary Customers	1,323	Customers	$151.83	$201	$276
		Primary Customers	155	Customers	$1,389.55	$215	$296
	Service & Transformer						
		Secondary Customers	1,323	Customers	$1,498.94	$1,983	$2,724
		Primary Customers	155	Customers	$687.64	$107	$146
FACILITIES	Feeder Backbone		505,045	kW, rateclass peak	$20.68	$10,444	$14,344
	Feeder Local Facilities		645,404	Design Demand	$7.16	$4,621	$6,347
DEMAND	Subtransmission		512,368	kW, rateclass peak	$7.31	$3,745	$5,144
	Substation		505,045	kW, rateclass peak	$13.75	$6,944	$9,537
SUBTOTAL						$28,262	$38,815

PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION COST
2015

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	76	Customers	$164.86	$13	$17
	Primary Meters	78	Customers	$1,389.55	$108	$148
	Service & Transformer					
	Secondary Customers	76	Customers	$4,057.83	$308	$424
	Primary Customers	78	Customers	$812.48	$63	$87
FACILITIES	Feeder Backbone	194,088	kW, rateclass peak	$21.44	$4,161	$5,715
	Feeder Local Facilities	263,581	Design Demand	$4.92	$1,297	$1,781
DEMAND	Subtransmission	196,902	kW, rateclass peak	$7.31	$1,439	$1,977
	Substation	194,088	kW, rateclass peak	$13.75	$2,669	$3,665
SUBTOTAL					$10,058	$13,814
Schedule 89 General Service (4,000 plus kW)						
CUSTOMER	Meters					
	Secondary Meters	1	Customers	$164.86	$0	$0
	Primary Meters	27	Customers	$1,389.55	$38	$52
	Substation Meters	8	Customers	$16,656.05	$133	$183
	Service & Transformer					
	Secondary Customers	1	Customers	$13,786.94	$14	$19
	Primary Customers	27	Customers	$2,550.00	$69	$95
FACILITIES	Feeder Backbone					
	Secondary Customers	1	Customers	$83,473.00	$83	$115
	Primary Customers	27	Customers	$83,473.00	$2,254	$3,095
	Subtransmission 115 kV Feeder	8	Customers	$89,081.00	$713	$979
DEMAND	Subtransmission	334,605	kW, rateclass peak	$7.31	$2,446	$3,359
	Substation (Sec. & Prim. Only)	206,796	kW, rateclass peak	$13.75	$2,843	$3,905
SUBTOTAL					$8,593	$11,802
Schedule 90 Primary Voltage Service						
CUSTOMER	Meters					
	Primary Meters	4	Customers	$1,389.55	$6	$8
	Service & Transformer					
	Primary Customers	4	Customers	$2,550.00	$10	$14
FACILITIES	Feeder Backbone					
	Primary Customers	4	Customers	$264,139.00	$1,057	$1,451
DEMAND	Subtransmission	204,126	kW, rateclass peak	$7.31	$1,492	$2,049
	Substation (Sec. & Prim. Only)	201,209	kW, rateclass peak	$13.75	$2,767	$3,800
SUBTOTAL					$5,331	$7,322
Schedules 91 & 95 Streetlighting & Highway Lighting						
CUSTOMER	Customer Service	158,469	Lights	$3.28	$519	$713
	Service & Transformer	158,469	Lights	$4.33	$686	$942
FACILITIES	Feeder Backbone	25,161	kW, rateclass peak	$24.65	$620	$852
	Feeder Local Facilities	25,161	Design Demand	$16.75	$421	$579
DEMAND	Subtransmission	25,526	kW, rateclass peak	$7.31	$187	$256
	Substation	25,161	kW, rateclass peak	$13.75	$346	$475
FIXED	Luminaires & Poles					**$7,796**
SUBTOTAL					$2,780	$11,613

PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION COST
2015

Grouping		Usages	Units & Basis	Marginal Unit Cost	Marginal Cost Revenues	Class Revenue Requirement
Schedule 92 Traffic Signals						
CUSTOMER	Service & Transformer	1,772	Intersections	$8.16	$14	$20
FACILITIES	Feeder Backbone	391	kW, rateclass peak	$24.65	$10	$13
	Feeder Local Facilities	391	Design Demand	$9.17	$4	$5
DEMAND	Subtransmission	397	kW, rateclass peak	$7.31	$3	$4
	Substation	391	kW, rateclass peak	$13.75	$5	$7
SUBTOTAL					$36	$49
Summary						
CUSTOMER	Meters	847,026	Customers		$20,726	$28,465
	Service & Transformer		Customers		$79,201	$108,776
	Customer Service	178,789	Lights		$586	$805
FACILITIES	Feeder Backbone	3,589,417	kW, rateclass peak		$92,059	$126,435
	Feeder Local Facilities	5,599,749	Design Demand		$75,806	$104,112
DEMAND	Subtransmission	4,180,195	kW, rateclass peak		$30,557	$41,968
	Substation	3,997,422	kW rateclass peak		$54,965	$75,489
FIXED	Luminaires & Poles					$9,792
TOTALS					$353,899	$495,843
					TARGET	$495,843
				EQUAL PERCENT		137.3%

PORTLAND GENERAL ELECTRIC
ALLOCATION OF METERING REVENUE REQUIREMENT
2015

Grouping	Customers	Marginal Unit Cost $ per Customer	Marginal Cost Revenues	Class Revenue Requirement
Schedule 7				
Single Phase	739,963	$0.35	$259	$1,743
Three Phase	85	$0.35	$0	$0
Schedule 15				
Residential	882	$0.00	$0	$0
Commercial	1,372	$0.00	$0	$0
Schedule 32				
Single Phase	54,240	$0.55	$30	$201
Three Phase	35,231	$0.55	$19	$130
Schedule 38				
Single Phase	51	$7.05	$0	$2
Three Phase	510	$7.05	$4	$24
Schedule 47				
Single Phase	208	$0.48	$0	$1
Three Phase	2,783	$0.48	$1	$9
Schedule 49				
Single Phase	3	$0.94	$0	$0
Three Phase	1,326	$0.94	$1	$8
Schedule 83				
Single Phase	655	$3.92	$3	$17
Three Phase	10,299	$3.92	$40	$272
Schedule 85				
Secondary	1,323	$9.95	$13	$89
Primary	155	$9.95	$2	$10
Schedule 85 1-4 MW				
Secondary	76	$6.79	$1	$3
Primary	78	$6.79	$1	$4
Schedule 89 GT 4 MW				
Secondary	1	$0.20	$0	$0
Primary	27	$0.20	$0	$0
Subtransmission	8	$0.20	$0	$0
Schedule 90-P	4	$0.20	$0	$0
Schedules 91/95	205	$0.00	$0	$0
Schedule 92	17	$0.00	$0	$0
TOTAL	849,502		$374	$2,514
			TARGET	$2,514
		EQUAL PERCENT		673%

PORTLAND GENERAL ELECTRIC
ALLOCATION OF BILLING REVENUE REQUIREMENT
2015

Grouping	Customers	Marginal Unit Cost $ per Customer	Marginal Cost Revenues	Class Revenue Requirement
Schedule 7				
Single Phase	739,963	$24.45	$18,092	$48,614
Three Phase	85	$24.45	$2	$6
Schedule 15				
Residential	882	$24.27	$21	$58
Commercial	1,372	$21.94	$30	$81
Schedule 32				
Single Phase	54,240	$23.04	$1,250	$3,358
Three Phase	35,231	$23.04	$812	$2,181
Schedule 38				
Single Phase	51	$27.07	$1	$4
Three Phase	510	$27.07	$14	$37
Schedule 47				
Single Phase	208	$19.59	$4	$11
Three Phase	2,783	$19.59	$55	$147
Schedule 49				
Single Phase	3	$25.45	$0	$0
Three Phase	1,326	$25.45	$34	$91
Schedule 83				
Single Phase	655	$56.74	$37	$100
Three Phase	10,299	$56.74	$584	$1,570
Schedule 85				
Secondary	1,323	$241.20	$319	$858
Primary	155	$241.20	$37	$101
Schedule 85 1-4 MW				
Secondary	76	$225.85	$17	$46
Primary	78	$225.85	$18	$47
Schedule 89 GT 4 MW				
Secondary	1	$192.37	$0	$1
Primary	27	$192.37	$5	$14
Subtransmission	8	$192.37	$2	$4
Schedule 90-P	4	$192.37	$1	$2
Schedules 91/95	205	$178.60	$37	$98
Schedule 92	17	$178.60	$3	$8
TOTAL	849,502		$21,375	$57,434
			TARGET	$57,434
		EQUAL PERCENT		269%

PORTLAND GENERAL ELECTRIC
ALLOCATION OF CONSUMER REVENUE REQUIREMENT
2015

Grouping	Customers	Marginal Unit Cost $ per Customer	Marginal Cost Revenues	Class Revenue Requirement
Schedule 7				
Single Phase	739,963	$9.18	$6,793	$39,358
Three Phase	85	$9.18	$1	$5
Schedule 15				
Residential	882	$5.92	$5	$30
Commercial	1,372	$5.76	$8	$46
Schedule 32				
Single Phase	54,240	$9.81	$532	$3,083
Three Phase	35,231	$9.81	$346	$2,002
Schedule 38				
Single Phase	51	$14.06	$1	$4
Three Phase	510	$14.06	$7	$42
Schedule 47				
Single Phase	208	$6.57	$1	$8
Three Phase	2,783	$6.57	$18	$106
Schedule 49				
Single Phase	3	$6.59	$0	$0
Three Phase	1,326	$6.59	$9	$51
Schedule 83				
Single Phase	655	$34.37	$23	$130
Three Phase	10,299	$34.37	$354	$2,051
Schedule 85				
Secondary	1,323	$345.60	$457	$2,650
Primary	155	$345.60	$54	$311
Schedule 85 1-4 MW				
Secondary	76	$1,545.53	$117	$681
Primary	78	$1,545.53	$120	$696
Schedule 89 GT 4 MW				
Secondary	1	$16,904.35	$17	$98
Primary	27	$16,904.35	$456	$2,644
Subtransmission	8	$16,904.35	$135	$784
Schedule 90-P	4	$16,904.35	$68	$392
Schedule 91/95	205	$100.93	$21	$120
Schedule 92	17	$47.02	$1	$5
TOTAL	849,502		$9,543	$55,295
			TARGET	$55,295
		EQUAL PERCENT		579%

PORTLAND GENERAL ELECTRIC

Allocation of Port Westward 2 Revenue Requirements

Schedule	Cycle MWh	Generation Revenues	PW 2 Allocation	PW 2 Price	Cycle Revenues
Schedule 7	7,462,740	$466,645,372	$23,154,749	3.10	$23,134,495
Schedule 15	15,972	$793,170	$39,357	2.46	$39,291
Schedule 32	1,556,500	$90,666,145	$4,498,816	2.89	$4,498,286
Schedule 38	43,599	$2,536,111	$125,841	2.89	$126,001
Schedule 47	18,147	$1,314,949	$65,247	3.60	$65,330
Schedule 49	69,025	$4,739,282	$235,161	3.41	$235,376
Schedule 83	2,735,660	$158,894,086	$7,884,258	2.88	$7,878,701
Schedule 85S	2,431,372	$137,185,885	$6,807,107	2.80	$6,807,841
Schedule 85P	645,752	$35,586,273	$1,765,776	2.73	$1,762,904
Schedule 89S	0	$0	$0	2.64	$0
Schedule 89P	913,928	$47,647,851	$2,364,267	2.59	$2,367,073
Schedule 89T	209,810	$10,801,448	$535,963	2.55	$535,015
Schedule 90P	1,453,535	$73,599,119	$3,651,958	2.51	$3,648,372
Schedule 91/95	97,094	$4,821,688	$239,250	2.46	$238,851
Schedule 92	3,327	$172,804	$8,574	2.58	$8,584
Totals	17,656,462	$1,035,404,184	$51,376,325		$51,346,121
Calendar Revenue Requirement			$51,371,664		
Add: Employee Discount			$25,162		
Revenue Requirement			$51,396,826		
Adjusted for Cycle			$51,376,325		

PORTLAND GENERAL ELECTRIC
Allocation of Tucannon Revenue Requirements

Schedule	Cycle MWh	Generation Revenues	Tucannon Allocation	Tucannon Price	Cycle Revenues
Schedule 7	7,462,740	$466,645,372	$21,032,170	2.82	$21,044,928
Schedule 15	15,972	$793,170	$35,749	2.24	$35,777
Schedule 32	1,556,500	$90,666,145	$4,086,413	2.63	$4,093,596
Schedule 38	43,599	$2,536,111	$114,305	2.62	$114,229
Schedule 47	18,147	$1,314,949	$59,266	3.27	$59,341
Schedule 49	69,025	$4,739,282	$213,604	3.09	$213,288
Schedule 83	2,735,660	$158,894,086	$7,161,514	2.62	$7,167,430
Schedule 85S	2,431,372	$137,185,885	$6,183,104	2.54	$6,175,684
Schedule 85P	645,752	$35,586,273	$1,603,909	2.48	$1,601,466
Schedule 89S	0	$0	$0	2.39	$0
Schedule 89P	913,928	$47,647,851	$2,147,536	2.35	$2,147,730
Schedule 89T	209,810	$10,801,448	$486,832	2.32	$486,759
Schedule 90P	1,453,535	$73,599,119	$3,317,185	2.28	$3,314,059
Schedule 91/95	97,094	$4,821,688	$217,318	2.24	$217,491
Schedule 92	3,327	$172,804	$7,788	2.34	$7,785
Totals	17,656,462	$1,035,404,184	$46,666,694		$46,679,563
Calendar Revenue Requirement			$46,662,461		
Add: Employee Discount			$22,855		
Revenue Requirement			$46,685,316		
Adjusted for Cycle			$46,666,694		

PORTLAND GENERAL ELECTRIC

PROPOSED
Summary of Area and Streetlighting Revenue

Schedule 15 - Area Lighting	
Fixtures & Maintenance	$1,196,481
Poles	$800,461
Energy (volumetric c/kWh rate)	$1,585,228
Total	**$3,582,170**

Schedule 91/95 - Street and Highway Lighting	
Fixtures & Maintenance (Options A&B)	$4,292,258
Poles (Options A&B)	$3,503,271
Energy (volumetric c/kWh rate)	$9,652,701
Total	**$17,448,229**

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	DAX Sch 91 & 95 A & B RATES A	B	C	TOTAL	Proposed Sch 91 & 95 A & B Counts A	B	C	TOTAL	Annual MWh	Annual Fixed Revenue A	Annual Fixed Revenue B	Annual Energy
79	Cobrahead - PD	HPS	70-watt	30	Standard	$0.00	$1.36	$2.98	$0.00	$2.76	$1.40		-	2	-	2	30	$0	$33	$72
84	Cobrahead - PD	HPS	100-watt	43	Standard	$0.00	$1.38	$4.27	$0.00	$3.38	$2.00		-	28,141	930	29,071	43	$0	$466,015	$1,489,598
85	Cobrahead - PD	HPS	150-watt	62	Standard	$0.00	$1.38	$6.15	$0.00	$4.26	$2.88		-	1,778	508	2,286	62	$0	$29,444	$168,707
89	Cobrahead - PD	HPS	200-watt	79	Standard	$0.00	$1.44	$7.84	$0.00	$5.11	$3.67		-	5,050	370	5,420	79	$0	$87,264	$509,914
86	Cobrahead - PD	HPS	250-watt	102	Standard	$0.00	$1.46	$10.12	$0.00	$6.20	$4.74		-	2,526	997	3,523	102	$0	$44,256	$427,833
87	Cobrahead - PD	HPS	400-watt	163	Standard	$0.00	$1.47	$16.17	$0.00	$9.05	$7.58		-	1,884	131	2,015	163	$0	$33,234	$390,991
33	Cobrahead	HPS	70-watt	30	Standard	$5.05	$1.61	$2.98	$6.45	$3.01	$1.40		-	881	1,024	1,905	30	$0	$17,021	$68,123
34	Cobrahead	HPS	100-watt	43	Standard	$4.99	$1.60	$4.27	$6.99	$3.60	$2.00		-	13,382	722	14,104	43	$0	$256,934	$722,689
35	Cobrahead	HPS	150-watt	62	Standard	$5.02	$1.61	$6.15	$7.90	$4.49	$2.88		-	6,848	827	7,675	62	$0	$132,303	$566,415
39	Cobrahead	HPS	200-watt	79	Standard	$5.76	$1.68	$7.84	$9.43	$5.35	$3.67		-	4,817	1,188	6,005	79	$0	$97,111	$564,950
36	Cobrahead	HPS	250-watt	102	Standard	$5.73	$1.68	$10.12	$10.47	$6.42	$4.74		-	2,089	1,251	3,340	102	$0	$42,114	$405,610
37	Cobrahead	HPS	400-watt	163	Standard	$6.14	$1.73	$16.17	$13.72	$9.31	$7.58		808	1,777	507	3,092	163	$59,533	$36,891	$599,972
31	Flood	HPS	250-watt	102	Standard	$6.47	$1.77	$10.12	$11.21	$6.51	$4.74		178	2	-	180	102	$13,820	$42	$21,859
32	Flood	HPS	400-watt	163	Standard	$6.47	$1.77	$16.17	$14.05	$9.35	$7.58		385	38	9	432	163	$29,891	$807	$83,825
40	Post-Top	HPS	100-watt	43	Standard	$5.75	$1.69	$4.27	$7.75	$3.69	$2.00		5,043	4,155	757	9,955	43	$347,967	$84,263	$510,094
76	Shoebox	HPS	70-watt	30	Standard	$6.40	$1.78	$2.98	$7.80	$3.18	$1.40		28	98	-	126	30	$2,150	$2,093	$4,506
77	Shoebox	HPS	100-watt	43	Standard	$6.59	$1.80	$4.27	$8.59	$3.80	$2.00		2,598	5,747	2,612	10,957	43	$205,450	$124,135	$561,437
78	Shoebox	HPS	150-watt	62	Standard	$6.85	$1.84	$6.15	$9.73	$4.72	$2.88		214	441	181	836	62	$17,591	$9,737	$61,697
81	Special Acorn	HPS	100-watt	43	Custom	$9.88	$2.17	$4.27	$11.88	$4.17	$2.00		856	3,839	503	5,198	43	$101,487	$99,968	$266,346
82	Victorian	HPS	150-watt	62	Custom	$9.78	$2.17	$6.15	$12.66	$5.05	$2.88		64	1,250	228	1,542	62	$7,511	$32,550	$113,800
49	Victorian	HPS	200-watt	79	Custom	$10.50	$2.29	$7.84	$14.17	$5.96	$3.67		3	184	-	187	79	$378	$5,056	$17,593
83	Victorian	HPS	250-watt	102	Custom	$10.55	$2.29	$10.12	$15.29	$7.03	$4.74		76	1,096	-	1,172	102	$9,622	$30,118	$142,328
64	Capitol Acorn	HPS	100-watt	43	Custom	$13.60	$2.63	$4.27	$15.60	$4.63	$2.00		-	65	-	65	43	$0	$2,051	$3,331
67	Capitol Acorn	HPS	150-watt	62	Custom	$13.54	$2.67	$6.15	$16.42	$5.55	$2.88		-	253	-	253	62	$0	$8,106	$18,671
65	Capitol Acorn	HPS	200-watt	79	Custom	$13.52	$2.66	$7.84	$17.19	$6.33	$3.67		-	70	-	70	79	$0	$2,234	$6,586
66	Capitol Acorn	HPS	250-watt	102	Custom	$13.54	$2.67	$10.12	$18.28	$7.41	$4.74		-	-	-	0	102	$0	$0	$0
12	Acorn - Indep.	HPS	100-watt	43	Custom	$9.88	$2.15	$4.27	$11.88	$4.15	$2.00		36	5	-	41	43	$4,268	$129	$2,101
13	Acorn - Indep.	HPS	150-watt	62	Custom	$9.59	$2.13	$6.15	$12.47	$5.01	$2.88		-	-	-	0	62	$0	$0	$0
98	Techtra	HPS	100-watt	43	Custom	$18.55	$3.23	$4.27	$20.55	$5.23	$2.00		538	42	-	580	43	$119,759	$1,628	$29,719
99	Techtra	HPS	150-watt	62	Custom	$18.06	$3.18	$6.15	$20.94	$6.06	$2.88		12	67	-	79	62	$2,601	$2,557	$5,830
88	Techtra	HPS	250-watt	102	Custom	$17.45	$3.14	$10.12	$22.19	$7.88	$4.74		-	191	-	191	102	$0	$7,197	$23,195
90	Westbrooke Acorn	HPS	70-watt	30	Custom	$12.62	$2.50	$2.98	$14.02	$3.90	$1.40		1	25	-	26	30	$151	$750	$930
91	Westbrooke Acorn	HPS	100-watt	43	Custom	$12.39	$2.47	$4.27	$14.39	$4.47	$2.00		-	31	-	31	43	$0	$919	$1,588
92	Westbrooke Acorn	HPS	150-watt	62	Custom	$12.40	$2.48	$6.15	$15.28	$5.36	$2.88		-	30	-	30	62	$0	$893	$2,214
93	Westbrooke Acorn	HPS	200-watt	79	Custom	$12.66	$2.54	$7.84	$16.33	$6.21	$3.67		-	2	-	2	79	$0	$61	$188
94	Westbrooke Acorn	HPS	250-watt	102	Custom	$12.51	$2.53	$10.12	$17.25	$7.27	$4.74		93	35	-	128	102	$13,961	$1,063	$15,544
62	Cobrahead	MH	150-watt	60	Custom	$5.65	$1.94	$5.95	$8.44	$4.73	$2.79		-	-	-	0	60	$0	$0	$0
61	Flood	MH	350-watt	139	Custom	$7.79	$2.22	$13.79	$14.25	$8.68	$6.46		-	-	-	0	139	$0	$0	$0
47	Flood	HPS	750-watt	285	Custom	$9.40	$2.71	$28.28	$22.65	$15.96	$13.25		54	-	-	54	285	$6,091	$0	$18,325
9	Mongoose	HPS	150-watt	62	Custom	$10.23	$2.22	$6.15	$13.11	$5.10	$2.88		-	27	-	27	62	$0	$719	$1,993
10	Mongoose	HPS	250-watt	102	Custom	$9.58	$2.16	$10.12	$14.32	$6.90	$4.74		-	8	-	8	102	$0	$207	$972
18	Ornamental Acorn Twin / Opt C	QL	85-watt	64	Custom	$0.00	$0.00	$6.35	$0.00	$0.00	$2.98		-	-	727	727	64	$0	$0	$55,397
20	Ornamental Acorn / Opt C	QL	55-watt	21	Custom	$0.00	$0.00	$2.08	$0.00	$0.00	$0.98		-	-	5	5	21	$0	$0	$125
26	Ornamental Acorn Twin / Opt C	QL	55-watt	42	Custom	$0.00	$0.00	$4.17	$0.00	$0.00	$1.95		-	-	4	4	42	$0	$0	$200
44	Composite Twin / Opt C	Comp	140-watt	54	Custom	$0.00	$0.00	$5.36	$0.00	$0.00	$2.51		-	-	16	16	54	$0	$0	$1,029
45	Composite Twin / Opt C	Comp	175-watt	66	Custom	$0.00	$0.00	$6.55	$0.00	$0.00	$3.07		-	-	16	16	66	$0	$0	$1,258
19	Cobrahead - (C) Only	MV	100-watt	39	Obsolete	$0.00	$0.00	$3.87	$0.00	$0.00	$1.81		-	-	1	1	39	$0	$0	$46
21	Cobrahead	MV	175-watt	66	Obsolete	$4.94	$1.55	$6.55	$8.01	$4.62	$3.07		-	1,348	86	1,434	66	$0	$25,073	$112,712
22	Cobrahead	MV	250-watt	94	Obsolete	$0.00	$0.00	$9.33	$0.00	$0.00	$4.37		-	-	33	33	94	$0	$0	$3,695
23	Cobrahead	MV	400-watt	147	Obsolete	$5.76	$1.68	$14.59	$12.60	$8.52	$6.84		347	64	85	496	147	$23,985	$1,290	$86,840
24	Cobrahead	MV	1,000-watt	374	Obsolete	$6.42	$2.01	$37.11	$23.81	$19.40	$17.39		12	2	2	16	374	$924	$48	$7,125
50	Special Box - Space-Glo	HPS	70-watt	30	Obsolete	$6.49	$1.70	$2.98	$7.89	$3.10	$1.40		21	-	-	21	30	$1,635	$0	$751
46	Special Box - Space-Glo	MV	175-watt	66	Obsolete	$6.44	$1.65	$6.55	$9.51	$4.72	$3.07		19	136	23	178	66	$1,468	$2,693	$13,991
51	Box - Gardco Hub / Opt C	HPS	Twin 70-watt	60	Obsolete	$0.00	$0.00	$5.95	$0.00	$0.00	$2.79		-	-	119	119	60	$0	$0	$8,497
52	Box - Gardco Hub / Opt C	HPS	70-watt	30	Obsolete	$0.00	$0.00	$2.98	$0.00	$0.00	$1.40		-	-	208	208	30	$0	$0	$7,438
53	Box - Gardco Hub	HPS	100-watt	43	Obsolete	$0.00	$2.06	$4.27	$0.00	$4.06	$2.00		-	3	-	3	43	$0	$74	$154
54	Box - Gardco Hub	HPS	150-watt	62	Obsolete	$0.00	$2.08	$6.15	$0.00	$4.96	$2.88		-	62	53	115	62	$0	$1,548	$8,487
55	Box - Gardco Hub / Opt C	HPS	250-watt	102	Obsolete	$0.00	$0.00	$10.12	$0.00	$0.00	$4.74		-	-	256	256	102	$0	$0	$31,089
56	Box - Gardco Hub / Opt C	HPS	400-watt	163	Obsolete	$0.00	$0.00	$16.17	$0.00	$0.00	$7.58		-	-	130	130	163	$0	$0	$25,225
58	Box - Gardco Hub	MH	250-watt	99	Obsolete	$0.00	$1.28	$9.82	$0.00	$5.88	$4.60		-	7	6	13	99	$0	$108	$1,532
59	Box - Gardco Hub	MH	400-watt	156	Obsolete	$0.00	$1.28	$15.48	$0.00	$8.53	$7.25		-	26	-	26	156	$0	$399	$4,830

PORTLAND GENERAL ELECTRIC
Schedules 91 & 95, Proposed Prices, Counts and Revenue

Lum				Monthly		Tariff Rates		Monthly	DAX Sch 91 & 95 A & B RATES				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	A	B	C	TOTAL	MWh	A	B	Energy
48	Cobrahead	MH	175-watt	71	Obsolete	$5.88	$1.77	$7.05	$9.18	$5.07	$3.30		-	3	57	60	71	$0	$64	$5,076
60	Flood	MH	400-watt	156	Obsolete	$6.67	$1.81	$15.48	$13.92	$9.06	$7.25		23	1	12	36	156	$1,841	$22	$6,687
69	Cobrahead DW 70/100	HPS	100-watt	43	Obsolete	$0.00	$1.61	$4.27	$0.00	$3.61	$2.00		-	89	-	89	43	$0	$1,719	$4,560
70	Cobrahead DW 100/150	HPS	100-watt	43	Obsolete	$0.00	$1.61	$4.27	$0.00	$3.61	$2.00		-	403	-	403	43	$0	$7,786	$20,650
71	Cobrahead DW 100/150	HPS	150-watt	62	Obsolete	$0.00	$1.63	$6.15	$0.00	$4.51	$2.88		-	303	5	308	62	$0	$5,927	$22,730
2	Victorian	QL	85-watt	32	Obsolete	$0.00	$0.77	$3.18	$0.00	$2.26	$1.49		-	11	414	425	32	$0	$102	$16,218
1	Victorian	QL	165-watt	60	Obsolete	$0.00	$1.04	$5.95	$0.00	$3.83	$2.79		-	104	271	375	60	$0	$1,298	$26,775
3	Techtra	QL	165-watt	60	Obsolete	$21.86	$1.23	$5.95	$24.65	$4.02	$2.79		4	156	-	160	60	$1,049	$2,303	$11,424
95	KIM SBC Shoebox	HPS	150-watt	62	Obsolete	$0.00	$2.64	$6.15	$0.00	$5.52	$2.88		-	35	71	106	62	$0	$1,109	$7,823
96	KIM Archetype	HPS	250-watt	102	Obsolete	$0.00	$2.87	$10.12	$0.00	$7.61	$4.74		-	65	28	93	102	$0	$2,239	$11,294
97	KIM Archetype	HPS	400-watt	163	Obsolete	$0.00	$2.27	$16.17	$0.00	$9.85	$7.58		-	18	33	51	163	$0	$490	$9,896
80	Acorn Type	HPS	70-watt	30	Obsolete	$9.85	$2.14	$2.98	$11.25	$3.54	$1.40		21	7	-	28	30	$2,482	$180	$1,001
73	GardCo Bronze - (C) Only	HPS	70-watt	30	Obsolete	$0.00	$0.00	$2.98	$0.00	$0.00	$1.40		-	-	30	30	30	$0	$0	$1,073
72	GardCo Bronze - (C) Only	MV	175-watt	66	Obsolete	$0.00	$0.00	$6.55	$0.00	$0.00	$3.07		-	-	124	124	66	$0	$0	$9,746
74	Acrylic Sphere - (C) Only	MV	400-watt	147	Obsolete	$0.00	$0.00	$14.59	$0.00	$0.00	$6.84		-	-	-	0	147	$0	$0	$0
25	Post-Top - Black	HPS	70-watt	30	Obsolete	$5.64	$1.58	$2.98	$7.04	$2.98	$1.40		1,651	1,242	-	2,893	30	$111,740	$23,548	$103,454
43	Rect.Type - (C) Only	HPS	200-watt	79	Obsolete	$0.00	$0.00	$7.84	$0.00	$0.00	$3.67		-	-	209	209	79	$0	$0	$19,663
5	Incand. - (C) Only	IND	92-watt	31	Obsolete	$0.00	$0.00	$3.08	$0.00	$0.00	$1.44		-	-	25	25	31	$0	$0	$924
6	Incand. - (C) Only	IND	182-watt	62	Obsolete	$0.00	$0.00	$6.15	$0.00	$0.00	$2.88		-	-	4	4	62	$0	$0	$295
29	Town and Country Post-Top	MV	175-watt	66	Obsolete	$5.65	$1.59	$6.55	$8.72	$4.66	$3.07		111	1,092	5	1,208	66	$7,526	$20,835	$94,949
27	Flood	HPS	70-watt	30	Obsolete	$4.87	$1.48	$2.98	$6.27	$2.88	$1.40		-	-	-	0	30	$0	$0	$0
30	Flood	HPS	100-watt	43	Obsolete	$5.03	$1.60	$4.27	$7.03	$3.60	$2.00		47	7	-	54	43	$2,837	$134	$2,767
38	Flood	HPS	200-watt	79	Obsolete	$6.45	$1.75	$7.84	$10.12	$5.42	$3.67		178	42	-	220	79	$13,777	$882	$20,698
41	Cobrahead - PD	HPS	310-watt	124	Obsolete	$6.13	$2.08	$12.30	$11.90	$7.85	$5.77		5	21	-	26	124	$368	$524	$3,838
14	Ornamental - (C) Only	HPS	100-watt	43	Obsolete	$0.00	$0.00	$4.27	$0.00	$0.00	$2.00		-	-	1,757	1,757	43	$0	$0	$90,029
15	Twin Ornamental -(C) Only	HPS	Twin 100-watt	86	Obsolete	$0.00	$0.00	$8.53	$0.00	$0.00	$4.00		-	-	2,229	2,229	86	$0	$0	$228,160
7	Flourescent - (C) Only	FLR	28-watt	12	Obsolete	$0.00	$0.00	$1.19	$0.00	$0.00	$0.56		-	-	13	13	12	$0	$0	$186
100	Cobrahead	LED	37-watt	13	Standard	$3.36	*	$1.29	$3.96	*	$0.60		1,802	-	-	1,802	13	$72,657	*	$27,895
101	Cobrahead	LED	50-watt	17	Standard	$3.36	*	$1.69	$4.15	*	$0.79		23,287	-	-	23,287	17	$938,932	*	$472,260
102	Cobrahead	LED	52-watt	18	Standard	$3.75	*	$1.79	$4.59	*	$0.84		1,626	-	-	1,626	18	$73,170	*	$34,926
103	Cobrahead	LED	67-watt	23	Standard	$4.18	*	$2.28	$5.25	*	$1.07		4,946	-	-	4,946	23	$248,091	*	$135,323
104	Cobrahead	LED	106-watt	36	Standard	$4.99	*	$3.57	$6.66	*	$1.67		1,457	-	-	1,457	36	$87,245	*	$62,418
110	Acorn	LED	60-Watt	21	Custom	$12.19	*	$2.08	$13.17	*	$0.98							$0	*	$0
111	Acorn	LED	70-Watt	24	Custom	$14.07	*	$2.38	$15.19	*	$1.12							$0	*	$0
112	Westbrooke (non-fluted)	LED	49-Watt	17	Custom	$16.97	*	$1.69	$17.76	*	$0.79							$0	*	$0
113	Westbrooke (non-fluted)	LED	69-Watt	24	Custom	$17.74	*	$2.38	$18.86	*	$1.12							$0	*	$0
114	Westbrooke (non-fluted)	LED	109-Watt	37	Custom	$18.01	*	$3.67	$19.73	*	$1.72							$0	*	$0
115	Westbrooke (non-fluted)	LED	136-Watt	46	Custom	$21.66	*	$4.56	$23.80	*	$2.14							$0	*	$0
116	Westbrooke (non-fluted)	LED	206-Watt	70	Custom	$21.66	*	$6.95	$24.92	*	$3.26							$0	*	$0
117	Westbrooke (fluted)	LED	49-Watt	17	Custom	$19.09	*	$1.69	$19.88	*	$0.79							$0	*	$0
118	Westbrooke (fluted)	LED	69-Watt	24	Custom	$19.44	*	$2.38	$20.56	*	$1.12							$0	*	$0
119	Westbrooke (fluted)	LED	109-Watt	37	Custom	$20.10	*	$3.67	$21.82	*	$1.72							$0	*	$0
120	Westbrooke (fluted)	LED	136-Watt	46	Custom	$22.97	*	$4.56	$25.11	*	$2.14							$0	*	$0
121	Westbrooke (fluted)	LED	206-Watt	70	Custom	$22.97	*	$6.95	$26.23	*	$3.26							$0	*	$0
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								Totals					**46,544**	**92,123**	**19,802**	**158,469**	**6,946**	**$2,531,960**	**$1,760,298**	**$9,652,701**

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

PORTLAND 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	$6.18	2,269	$168,269
59	Bronze	Fiberglass	30	A	$9.74	2,571	$300,498
61	Gray	Fiberglass	30	A	$10.50	3,187	$401,562
1	Standard	Wood	30 to 35	A	$7.03	3,994	$336,934
3	Standard	Wood	40 to 55	A	$9.20	628	$69,331
58	Black	Fiberglass	20	B	$0.14	5,429	$9,121
60	Bronze	Fiberglass	30	B	$0.22	6,634	$17,514
62	Gray	Fiberglass	30	B	$0.24	12,143	$34,972
46	Standard	Wood	30 to 35	B	$0.16	1,018	$1,955
47	Standard	Wood	40 to 55	B	$0.21	211	$532
31	Regular	Aluminum	16	A	$8.39	568	$57,186
32	Regular	Aluminum	25	A	$13.93	5,370	$897,649
33	Regular	Aluminum	30	A	$15.05	279	$50,387
28	Regular	Aluminum	35	A	$18.00	93	$20,088
18	Davit	Aluminum	25	A	$13.90	74	$12,343
6	Davit	Aluminum	30	A	$13.83	454	$75,346
29	Davit	Aluminum	35	A	$15.12	181	$32,841
70	Davit with 8-foot Arm	Aluminum	40	A	$20.52	9	$2,216
27	Double Davit	Aluminum	30	A	$20.42	22	$5,391
65	Fluted Victorian Ornamental	Aluminum	14	A	$12.29	36	$5,309
69	Non-fluted Techtra Ornamenta	Aluminum	18	A	$24.18	533	$154,655
66	Fluted Ornamental	Aluminum	16	A	$12.56	102	$15,373
77	HADCO Non-fluted Ornamenta	Aluminum	16	A	$25.69	1	$308
79	Fluted Westbrooke	Aluminum	18	A	$24.24	0	$0
81	Non-fluted Westbrooke	Aluminum	18	A	$25.69	73	$22,504
43	Painted Ornamental - Portland	Aluminum	35	A	$41.28	0	$0
85	Decorative Ameron	Concrete	20	A	$24.12	0	$0
4	Ameron Post Top	Concrete	25	A	$24.12	0	$0
63	Fluted Ornamental -Black	Fiberglass	14	A	$14.86	645	$115,016
83	Smooth	Fiberglass	18	A	$6.16	0	$0
67	Regular - Color may vary	Fiberglass	22	A	$5.51	22	$1,455
68	Regular - Color may vary	Fiberglass	35	A	$9.04	159	$17,248
16	Anchor Base -Gray	Fiberglass	35	A	$16.51	34	$6,736
35	Direct Bury with Shroud	Fiberglass	18	A	$9.96	4	$478
34	Regular	Aluminum	16	B	$0.19	110	$251
8	Regular	Aluminum	25	B	$0.31	2,036	$7,574
48	Regular	Aluminum	30	B	$0.34	709	$2,893
54	Regular	Aluminum	35	B	$0.40	572	$2,746
13	Davit	Aluminum	25	B	$0.31	127	$472
12	Davit	Aluminum	30	B	$0.31	1,555	$5,785
53	Davit	Aluminum	35	B	$0.34	2,035	$8,303
76	Davit with 8-foot Arm	Aluminum	40	B	$0.46	207	$1,143

PORTLAND GENERAL ELECTRIC

Schedule 91 Poles, Forecasted Revenue at Proposed Prices

Pole CODE	Pole Description	Material	Pole Height	Option	Tariff Rates	Counts	Annual Revenues
14	Double Davit	Aluminum	30	B	$0.46	63	$348
71	Fluted Victorian Ornamental	Aluminum	14	B	$0.28	1,179	$3,961
75	Non-fluted Techtra Ornamenta	Aluminum	18	B	$0.54	449	$2,910
72	Fluted Ornamental	Aluminum	16	B	$0.28	1,852	$6,223
78	HADCO Non-fluted Ornamenta	Aluminum	16	B	$0.58	43	$299
80	Fluted Westbrooke	Aluminum	18	B	$0.54	20	$130
82	Non-fluted Westbrooke	Aluminum	18	B	$0.58	49	$341
44	Painted Ornamental - Portland	Aluminum	35	B	$0.92	62	$684
86	Decorative Ameron	Concrete	20	B	$0.54	0	$0
5	Ameron Post Top	Concrete	25	B	$0.54	50	$324
64	Fluted Ornamental -Black	Fiberglass	14	B	$0.33	2,173	$8,605
84	Smooth	Fiberglass	18	B	$0.14	0	$0
73	Regular - Color may vary	Fiberglass	22	B	$0.12	513	$739
74	Regular - Color may vary	Fiberglass	35	B	$0.20	1,912	$4,589
17	Anchor Base -Gray	Fiberglass	35	B	$0.37	64	$284
36	Direct Bury with Shroud	Fiberglass	18	B	$0.22	559	$1,476
2	Post	Aluminum	30	A	$8.39	601	$60,509
30	Ornamental Post	Concrete	35 or less	A	$13.93	59	$9,862
37	Painted Regular	Steel	25	A	$13.93	594	$99,293
38	Painted Regular	Steel	30	A	$15.05	195	$35,217
39	Laminated without Mast Arm	Wood	20	A	$6.18	2,891	$214,397
24	Laminted SLO Pole	Wood	20	A	$6.18	299	$22,174
41	Curved laminated	Wood	30	A	$9.74	924	$107,997
11	Painted Underground	Wood	35	A	$7.03	544	$45,892
22	Painted SLO Pole	Wood	35	A	$7.03	50	$4,218
55	Bronze Alloy GardCo	Bronze	12	B	$0.17	21	$43
25	Ornamental Post	Concrete	35 or less	B	$0.31	288	$1,071
7	Painted Regular	Steel	25	B	$0.31	378	$1,406
49	Painted Regular	Steel	30	B	$0.34	48	$196
21	Unpainted with 6-foot Mast Arm	Steel	30	B	$0.31	55	$205
51	Unpainted with 6-foot Davit Arn	Steel	30	B	$0.31	43	$160
40	Unpainted with 8-foot Mast Arm	Steel	35	B	$0.34	118	$481
42	Unpainted with 8-foot Davit Arn	Steel	35	B	$0.34	18	$73
23	Laminated without Mast Arm	Wood	20	B	$0.14	2,433	$4,087
45	Curved laminated	Wood	30	B	$0.22	142	$375
26	Painted Underground	Wood	35	B	$0.16	1,207	$2,317

Total Option As	27,465	$3,368,685
Total Option Bs	46,525	$134,586
	73,990	$3,503,271

PORTLAND GENERAL ELECTRIC
Schedule 15, Proposed Tariff Prices, Counts and Revenue

					Monthly Tariff Price			Annual		Revenues		
Code	**Description**	**Type**	**Size**	**kWh**	**Fixed**	**Energy**	**Total**	**Count**	**MWh**	**Fixed**	**Energy**	**Total**
Fixtures												
21	Cobrahead	MV	175-watt	66	$6.02	$6.55	$12.57	517	409	$37,348	$40,636	$77,984
23	Cobrahead	MV	400-watt	147	$6.41	$14.59	$21.00	1,856	3,274	$142,764	$324,948	$467,712
24	Cobrahead	MV	1000-watt	374	$7.07	$37.11	$44.18	97	435	$8,229	$43,196	$51,426
33	Cobrahead - (non-pd)	HPS	70-watt	30	$6.13	$2.98	$9.11	56	20	$4,119	$2,003	$6,122
34	Cobrahead - (non-pd)	HPS	100-watt	43	$6.07	$4.27	$10.34	0	0	$0	$0	$0
35	Cobrahead - (non-pd)	HPS	150-watt	62	$6.10	$6.15	$12.25	0	0	$0	$0	$0
39	Cobrahead - (non-pd)	HPS	200-watt	79	$6.41	$7.84	$14.25	125	119	$9,615	$11,760	$21,375
36	Cobrahead - (non-pd)	HPS	250-watt	102	$6.38	$10.12	$16.50	64	78	$4,900	$7,772	$12,672
41	Cobrahead - (PD)	HPS	310-watt	124	$6.78	$12.30	$19.08	6	9	$488	$886	$1,374
37	Cobrahead - (non-pd)	HPS	400-watt	163	$6.79	$16.17	$22.96	1,649	3,225	$134,361	$319,972	$454,332
30	Flood	HPS	100-watt	43	$6.11	$4.27	$10.38	277	143	$20,310	$14,193	$34,503
38	Flood	HPS	200-watt	79	$7.10	$7.84	$14.94	498	472	$42,430	$46,852	$89,281
31	Flood	HPS	250-watt	102	$7.12	$10.12	$17.24	739	905	$63,140	$89,744	$152,884
32	Flood	HPS	400-watt	163	$7.12	$16.17	$23.29	1,835	3,589	$156,782	$356,063	$512,846
76	Shoebox	HPS	70-watt	30	$7.48	$2.98	$10.46	0	0	$0	$0	$0
77	Shoebox	HPS	100-watt	43	$7.67	$4.27	$11.94	585	302	$53,843	$29,975	$83,819
78	Shoebox	HPS	150-watt	62	$7.93	$6.15	$14.08	96	71	$9,135	$7,085	$16,220
81	Special Acorn	HPS	100-watt	43	$10.53	$4.27	$14.80	360	186	$45,490	$18,446	$63,936
82	HADCO - Victorian	HPS	150-watt	62	$10.43	$6.15	$16.58	23	17	$2,879	$1,697	$4,576
49	HADCO - Victorian	HPS	200-watt	79	$11.15	$7.84	$18.99	0	0	$0	$0	$0
83	HADCO - Victorian	HPS	250-watt	102	$11.20	$10.12	$21.32	0	0	$0	$0	$0
40	Early American Post-Top	HPS	100-watt	43	$6.83	$4.27	$11.10	83	43	$6,803	$4,253	$11,056
62	Cobrahead	MH	150-watt	60	$6.73	$5.95	$12.68	0	0	$0	$0	$0
48	Cobrahead	MH	175-watt	71	$6.96	$7.05	$14.01	0	0	$0	$0	$0
61	Flood	MH	350-watt	139	$8.44	$13.79	$22.23	0	0	$0	$0	$0
60	Flood	MH	400-watt	156	$7.32	$15.48	$22.80	14	26	$1,230	$2,601	$3,830
47	Flood	HPS	750-watt	285	$10.05	$28.28	$38.33	116	397	$13,990	$39,366	$53,355
12	HADCO Independence	HPS	100-watt	43	$10.53	$4.27	$14.80	13	7	$1,643	$666	$2,309
13	HADCO Independence	HPS	150-watt	62	$10.24	$6.15	$16.39	7	5	$860	$517	$1,377
64	HADCO Capitol Acorn	HPS	100-watt	43	$14.25	$4.27	$18.52	9	5	$1,539	$461	$2,000
67	HADCO Capitol Acorn	HPS	150-watt	62	$14.19	$6.15	$20.34	0	0	$0	$0	$0
65	HADCO Capitol Acorn	HPS	200-watt	79	$14.17	$7.84	$22.01	0	0	$0	$0	$0
66	HADCO Capitol Acorn	HPS	250-watt	102	$14.19	$10.12	$24.31	0	0	$0	$0	$0
98	HADCO Techtra	HPS	100-watt	43	$19.20	$4.27	$23.47	0	0	$0	$0	$0
99	HADCO Techtra	HPS	150-watt	62	$18.71	$6.15	$24.86	2	1	$449	$148	$597
88	HADCO Techtra	HPS	250-watt	102	$18.10	$10.12	$28.22	0	0	$0	$0	$0
90	HADCO Westbrooke	HPS	70-watt	30	$13.27	$2.98	$16.25	0	0	$0	$0	$0
91	HADCO Westbrooke	HPS	100-watt	43	$13.04	$4.27	$17.31	0	0	$0	$0	$0
92	HADCO Westbrooke	HPS	150-watt	62	$13.05	$6.15	$19.20	0	0	$0	$0	$0
93	HADCO Westbrooke	HPS	200-watt	79	$13.31	$7.84	$21.15	0	0	$0	$0	$0
94	HADCO Westbrooke	HPS	250-watt	102	$13.16	$10.12	$23.28	0	0	$0	$0	$0
96	KIM Archetype	HPS	250-watt	102	$15.99	$10.12	$26.11	0	0	$0	$0	$0
97	KIM Archetype	HPS	400-watt	163	$11.16	$16.17	$27.33	0	0	$0	$0	$0
9	Holophane Mongoose	HPS	150-watt	62	$10.88	$6.15	$17.03	1	1	$131	$74	$204
10	Holophane Mongoose	HPS	250-watt	102	$10.23	$10.12	$20.35	0	0	$0	$0	$0
100	Cobrahead	LED	37-watt	13	$3.77	$1.29	$5.06	0		$0	$0	$0
101	Cobrahead	LED	50-watt	17	$3.77	$1.69	$5.46	0		$0	$0	$0
102	Cobrahead	LED	52-watt	18	$4.16	$1.79	$5.95	0		$0	$0	$0
103	Cobrahead	LED	67-watt	23	$4.43	$2.28	$6.71	0		$0	$0	$0
104	Cobrahead	LED	106-watt	36	$5.25	$3.57	$8.82	0		$0	$0	$0
110	Acorn	LED	60-Watt	21	$12.64	$2.08	$14.72	0		$0	$0	$0
111	Acorn	LED	70-Watt	24	$14.48	$2.38	$16.86	0		$0	$0	$0
112	Westbrooke (non-flare)	LED	49-Watt	17	$17.31	$1.69	$19.00	0		$0	$0	$0
113	Westbrooke (non-flare)	LED	69-Watt	24	$18.06	$2.38	$20.44	0		$0	$0	$0
114	Westbrooke (non-flare)	LED	109-Watt	37	$18.32	$3.67	$21.99	0		$0	$0	$0
115	Westbrooke (non-flare)	LED	136-Watt	46	$21.89	$4.56	$26.45	0		$0	$0	$0
116	Westbrooke (non-flare)	LED	206-Watt	70	$21.89	$6.95	$28.84	0		$0	$0	$0
117	Westbrooke (flare)	LED	49-Watt	17	$19.38	$1.69	$21.07	0		$0	$0	$0
118	Westbrooke (flare)	LED	69-Watt	24	$19.72	$2.38	$22.10	0		$0	$0	$0
119	Westbrooke (flare)	LED	109-Watt	37	$20.37	$3.67	$24.04	0		$0	$0	$0
120	Westbrooke (flare)	LED	136-Watt	46	$23.17	$4.56	$27.73	0		$0	$0	$0
121	Westbrooke (flare)	LED	206-Watt	70	$23.17	$6.95	$30.12	0		$0	$0	$0
122	CREE XSP	LED	25-Watt	9	$2.81	$0.89	$3.70	987		$33,282	$10,541	$43,823
123	CREE XSP	LED	42-Watt	14	$2.91	$1.39	$4.30	6,296		$219,856	$105,017	$324,874
124	CREE XSP	LED	48-Watt	16	$3.38	$1.59	$4.97	1,025		$41,574	$19,557	$61,131
125	CREE XSP	LED	56-Watt	19	$3.89	$1.89	$5.78	1,645		$76,789	$37,309	$114,097
126	CREE XSP	LED	91-Watt	31	$3.89	$3.08	$6.97	1,339		$62,505	$49,489	$111,994
Totals								9,028	13,740	$1,196,481	$1,585,228	$2,125,791

PORTLAND GENERAL ELECTRIC
Schedule 15, Proposed Tariff Prices, Counts and Revenue

					Monthly Tariff Price				Annual		Revenues	
Code	**Description**	**Type**	**Size**	**kWh**	**Fixed**	**Energy**	**Total**	**Count**	**MWh**	**Fixed**	**Energy**	**Total**
Poles												
1	Standard	Wood	30 to 35				$7.03	5,669				$478,237
3	Standard	Wood	40 to 55				$9.20	452				$49,901
11	Painted Underground	Wood	35				$7.03	113				$9,533
41	Curved laminated	Wood	30				$8.71	61				$6,376
31	Regular	Aluminum	16				$8.39	26				$2,618
32	Regular	Aluminum	25				$13.93	11				$1,839
33	Regular	Aluminum	30				$15.05	20				$3,612
28	Regular	Aluminum	35				$18.00	3				$648
65	Fluted Ornamental	Aluminum	14				$12.29	19				$2,802
18	Davit	Aluminum	25				$12.88	0				$0
6	Davit	Aluminum	30				$13.83	23				$3,817
29	Davit	Aluminum	35				$15.12	0				$0
70	Davit with 8-foot Arm	Aluminum	40				$20.52	0				$0
27	Double Davit	Aluminum	30				$20.42	3				$735
66	HADCO, Fluted Ornamental	Aluminum	16				$12.56	2				$301
69	HADCO, Non-fluted Techtra Ornamental	Aluminum	18				$24.18	19				$5,513
4	Ameron Post-Top	Concrete	25				$24.12	0				$0
63	Fluted Ornamental Black	Fiberglass	14				$14.86	176				$31,384
57	Regular Black	Fiberglass	20				$6.18	303				$22,470
61	Regular Gray	Fiberglass	30				$10.50	1,292				$162,792
68	Regular Other Colors	Fiberglass	35				$9.04	40				$4,339
16	Anchor Base Gray	Fiberglass	35				$16.51	2				$396
35	Direct Bury with Shroud	Fiberglass	18				$9.96	110				$13,147
79	Fluted Westbrooke	Aluminum	18				$25.44					
81	Non-Fluted Westbrooke	Aluminum	18				$26.97					
Totals								8,344				$800,461

Totals Luminaires and Poles $2,926,251

PORTLAND GENERAL ELECTRIC
2015 Projected Line Loss Percents by Delivery Voltage

Delivery Voltage	Internal Loss Factor	External Loss Factor	Total Loss Factor
Secondary	4.74%	2.11%	6.85%
Primary	2.85%	2.11%	4.96%
Subtransmission	1.45%	2.11%	3.56%