Portland General Electric Company
121 SW Salmon Street • Portland, Oregon 97204
(503) 464-2095 • Facsimile (503) 464-2222

Maria M. Pope
Senior Vice President, Finance
Chief Financial Officer & Treasurer

February 16, 2010

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

RE: **Advice No. 10-04, Portland General Electric General Rate Revision**

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

Enclosed are 30 copies including 10 courtesy copies of Direct Testimony, Exhibits and a Pretrial Brief that conforms to the requirements in OAR 860-013-0075 for a general rate revision. Also enclosed is an original and one copy of a Motion for Protective Order. 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 will be provided after the Protective Order has been issued. By April 1st, we will file the remaining power cost updates.

The tariff changes are filed with an effective date of March 18, 2010, 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, 2011.

To ensure a timely response, please direct your communications related to this filing to the following email address: pge.opuc.filings@pgn.com

Please mail hardcopies to:

Rates and Regulatory Affairs
121 SW Salmon St, 1WTC0702
Portland, Oregon 97204
(503) 464-7857

Doug Tingey
121 SW Salmon St, 1WTC1301
Portland, Oregon 97204
(503) 464-8926

Sincerely,

Maria Pope

Enclosures
cc: Service List – UE 197 (Electronic only)

Advice No. 10-04
Portland General Electric General Rate Revision
Revised Tariff Sheets filed February 16, 2010

Fifth Revision of Sheet No. 1-1
Eleventh Revision of Sheet No. 1-3
Fourth Revision of Sheet No. 1-4
Fourth Revision of Sheet No. 7-1
First Revision of Sheet No. 7-5
Second Revision of Sheet No. 9-1
First Revision of Sheet No. 12-1
Third Revision of Sheet No. 15-1
Third Revision of Sheet No. 15-2
Third Revision of Sheet No. 15-3
Third Revision of Sheet No. 32-1
Second Revision of Sheet No. 32-4
First Revision of Sheet No. 32-5
First Revision of Sheet No. 32-6
Fourth Revision of Sheet No. 38-1
Third Revision of Sheet No. 38-3
Third Revision of Sheet No. 47-1
Fourth Revision of Sheet No. 49-1
Fifth Revision of Sheet No. 75-1
Second Revision of Sheet No. 75-5
First Revision of Sheet No. 75-6
Fifth Revision of Sheet No. 76R-1
Second Revision of Sheet No. 76R-3
Second Revision of Sheet No. 76R-4
Second Revision of Sheet No. 76R-5
Second Revision of Sheet No. 77-2
First Revision of Sheet No. 77-4
Third Revision of Sheet No. 81-1
Fifth Revision of Sheet No. 83-1
Fourth Revision of Sheet No. 83-2
Second Revision of Sheet No. 83-3
Second Revision of Sheet No. 84-1
First Revision of Sheet No. 84-2
Second Revision of Sheet No. 84-3
Original Sheet No. 85-1
Original Sheet No. 85-2
Original Sheet No. 85-3
Original Sheet No. 85-4
Second Revision of Sheet No. 86-1
Second Revision of Sheet No. 87-2
First Revision of Sheet No. 88-1
Fifth Revision of Sheet No. 89-1
Fourth Revision of Sheet No. 89-2
Fourth Revision of Sheet No. 91-7
Fifth Revision of Sheet No. 91-8
Third Revision of Sheet No. 91-9
Second Revision of Sheet No. 91-10
Second Revision of Sheet No. 91-11
First Revision of Sheet No. 91-12
First Revision of Sheet No. 91-13
First Revision of Sheet No. 91-14
First Revision of Sheet No. 91-16
Fourth Revision of Sheet No. 92-1
Fourth Revision of Sheet No. 93-1
Fourth Revision of Sheet No. 94-1
Sixteenth Revision of Sheet No. 100-1
Fourth Revision of Sheet No. 105-1
Fourth Revision of Sheet No. 105-2
Fourth Revision of Sheet No. 105-3
Second Revision of Sheet No. 109-1
Second Revision of Sheet No. 109-2
Second Revision of Sheet No. 109-3
First Revision of Sheet No. 110-2
First Revision of Sheet No. 110-3
First Revision of Sheet No. 111-1
First Revision of Sheet No. 111-2
First Revision of Sheet No. 111-3
First Revision of Sheet No. 121-1
First Revision of Sheet No. 121-2
Second Revision of Sheet No. 122-1
Second Revision of Sheet No. 122-2
Second Revision of Sheet No. 123-1
Second Revision of Sheet No. 123-2
First Revision of Sheet No. 123-3
First Revision of Sheet No. 123-4
Second Revision of Sheet No. 123-5
Original Sheet No. 123-6
Second Revision of Sheet No. 125-1
Fifth Revision of Sheet No. 125-2
Fifth Revision of Sheet No. 125-3
Fourth Revision of Sheet No. 126-1
Second Revision of Sheet No. 126-2
Third Revision of Sheet No. 126-3
Third Revision of Sheet No. 126-4

Third Revision of Sheet No. 126-5
Eighth Revision of Sheet No. 128-1
Eighth Revision of Sheet No. 128-2
Eighth Revision of Sheet No. 128-4
Seventh Revision of Sheet No. 128-5
Sixth Revision of Sheet No. 128-6
Second Revision of Sheet No. 129-1
Eighth Revision of Sheet No. 129-3
Second Revision of Sheet No. 129-4
First Revision of Sheet No. 133-1
First Revision of Sheet No. 133-2
First Revision of Sheet No. 133-3
Original Sheet No. 141-1
Original Sheet No. 141-2
Original Sheet No. 141-3
Original Sheet No. 141-4
Original Sheet No. 145-1
Original Sheet No. 145-2
Original Sheet No. 145-3
Second Revision of Sheet No. 300-5
First Revision of Sheet No. 300-6
Original Sheet No. 485-1
Original Sheet No. 485-2
Original Sheet No. 485-3
Original Sheet No. 485-4
Original Sheet No. 485-5
Original Sheet No. 485-6
Fifth Revision of Sheet No. 489-1
Fourth Revision of Sheet No. 489-3
Second Revision of Sheet No. 489-4
Second Revision of Sheet No. 489-5
Third Revision of Sheet No. 515-1
Third Revision of Sheet No. 515-2
Third Revision of Sheet No. 532-1
Fourth Revision of Sheet No. 538-1
Fourth Revision of Sheet No. 549-1
Fifth Revision of Sheet No. 575-1
Fifth Revision of Sheet No. 576R-1
Fifth Revision of Sheet No. 583-1
Second Revision of Sheet No. 583-2
Original Sheet No. 585-1
Original Sheet No. 585-2
Original Sheet No. 585-3
Fifth Revision of Sheet No. 589-1
Fifth Revision of Sheet No. 591-6
Sixth Revision of Sheet No. 591-7
Third Revision of Sheet No. 591-8
Second Revision of Sheet No. 591-10
First Revision of Sheet No. 591-11
First Revision of Sheet No. 591-12
Fourth Revision of Sheet No. 592-1
Fifth Revision of Sheet No. 594-1
First Revision of Sheet No. 600-3
First Revision of Sheet No. G-1

The following sheets are **withdrawn:**

Third Revision of Sheet No. 483-1
Sixth Revision of Sheet No. 483-2
Third Revision of Sheet No. 483-3
First Revision of Sheet No. 483-4
First Revision of Sheet No. 483-5
Original Sheet No. 483-6

Schedule 483, is being withdrawn in its entirety. Schedule 485 is the proposed replacement for Schedule 483.

PORTLAND GENERAL ELECTRIC COMPANY
TABLE OF CONTENTS
RATE SCHEDULES

PORTLAND GENERAL ELECTRIC COMPANY
TABLE OF CONTENTS
RATE SCHEDULES

PORTLAND GENERAL ELECTRIC COMPANY
TABLE OF CONTENTS
RATE SCHEDULES

TABLE OF CONTENTS
RATE SCHEDULES (Concluded)

SCHEDULE 7
RESIDENTIAL SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Residential Customers.

MONTHLY RATE

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

Basic Charge			
Single Phase Service	$10.00		
Three Phase Service	$14.00		(I)
Transmission and Related Services Charge	0.243	¢ per kWh	(I)
Distribution Charge	3.349	¢ per kWh	(I)
Energy Charge			
Standard Service			
First 500 kWh	5.900	¢ per kWh	(I)(C)
501 – 1,000 kWh	7.643	¢ per kWh	(I)(C)
Over 1,000 kWh	8.400	¢ per kWh	(I)(C)
Time-of-Use (TOU) Portfolio Option (enrollment is necessary)			
On-Peak Period	13.527	¢ per kWh	(I)
Mid-Peak Period	7.643	¢ per kWh	(I)
Off-Peak Period	4.509	¢ per kWh	(I)
First 500 kWh block adjustment	(1.743)	¢ per kWh	(I)(C)
Over 1,000 kWh block adjustment	0.757	¢ per kWh	(I)(C)
			(D)

* See Schedule 100 for applicable adjustments.

SCHEDULE 7 (Concluded)

SPECIAL CONDITIONS (Continued)

Pertaining to the TOU Option (Continued) **(D)**

4. The Customer must provide the Company access to the meter on a monthly basis. **(T)**

5. After a Customer's initial 12 months of service on the TOU Option, the Company will calculate what the Customer would have paid under Standard Service and compare billings. If the Customer's Energy Charge billings (including all applicable supplemental adjustments) under the TOU Option exceeded Standard Service Energy Charge (including all applicable supplemental adjustments) by more than 10%, the Company will issue the Customer a refund for the amount in excess of 10% either as a bill credit or refund check. No refund will be issued for Customers not meeting the 12 month requirement. **(T)** **(C)**

6. The Company may recover lost revenue from the TOU Option through Schedule 105. **(T)**

7. Billing will begin for any Customer on the next regularly scheduled meter reading date following the initialization meter reading made on a regularly scheduled meter reading date. **(T)**

8. The Company may choose to offer promotional incentives, including but not limited to rebates or coupons. **(T)**

SCHEDULE 9
STABLE RATE PILOT
(NO NEW SERVICE)

PURPOSE

This pilot is a renewable Portfolio option which provides price stability and promotes the development of new renewable energy resources.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To the first 5 aMW (43,800,000 kWh) of total estimated annual load from Residential and Small Nonresidential Customers. This schedule is available only to those customers enrolled under Schedule 9 as of May 31, 2007.

MONTHLY RATE

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

Basic Charge:

Residential Basic Charge:		
Single Phase	$10.00[1]	**(I)**
Three Phase	$14.00[1]	
Nonresidential Basic Charge		
Single Phase	$12.00[1]	
Three Phase	$16.00[1]	

Stable Rate:

Residential Stable Rate	8.780 ¢ per kWh[2]
Nonresidential Stable Rate	9.740 ¢ per kWh[2]
Wind Development Fund	0.300 ¢ per kWh[2]

(1) The Basic Charge for Residential and Nonresidential Customers under this schedule will mirror the Basic Charge in Schedule 7 and Schedule 32. The Basic Charge may fluctuate with changes in the respective schedules.
(2) The Residential Stable Rate, the Nonresidential Stable Rate and Wind Development Fund (WDF) Charge will not be modified for the term of this pilot.

SCHEDULE 12
RESIDENTIAL CRITICAL PEAK PRICING PILOT

PURPOSE

This Critical Peak Pricing (CPP) pilot is a demand response option for eligible residential Customers. CPP provides Customers a price incentive to curtail peak loads during Critical Peak hours up to ten days for each six month season. The Company will notify the Customer on the day prior to each Load Reduction Day. The CPP pilot is expected to be conducted from November 1, 2010 through October 31, 2012.

AVAILABLE

In all territory served by the Company.

APPLICABLE

Subject to selection by the Company, approximately 2,000 eligible Residential (Schedule 7) Customers may elect to participate in the CPP pilot. Eligible Customers must have an Advanced Metering Infrastructure (AMI) meter. Participating Customers will be transferred from Schedule 7 to Schedule 12 for the season(s) of participation in the CPP pilot.

MONTHLY RATE

For purposes of this schedule, there are two seasons, Summer (May 1 – October 31) and Winter (November 1 – April 30). For each season a Customer participates in the CPP pilot, the Customer will be billed pursuant to this Schedule 12. For Customers who participate in the CPP pilot for only one season, Schedule 12 will apply for the season the Customer participates in the CPP pilot, and Schedule 7 will apply for the season the Customer does not participate in the CPP pilot.

Subject to approved rate revisions prior to CPP pilot implementation, the sum of the following charges per Point of Delivery (POD)* will apply to Customers participating in the CPP pilot:

<u>Basic Charge</u>			
Single Phase Service	$10.00		
Three Phase Service	$14.00		**(I)**
<u>Transmission and Related Services Charge</u>	0.243	¢ per kWh	
<u>Distribution Charge</u>	3.349	¢ per kWh	
<u>Energy Charge</u>			
Off-Peak Period	6.100	¢ per kWh	
On-Peak Period	7.600	¢ per kWh	
Critical Peak (when called)	35.930	¢ per kWh	**(I)**

* See Schedule 100 for applicable adjustments.

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	0.195	¢ per kWh	**(I)**
Distribution Charge	3.654	¢ per kWh	**(I)**
Cost of Service Energy Charge	5.540	¢ 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	$11.89 [2]	(I)
	400	21,000	147	19.56 [2]	
	1,000	55,000	374	41.71 [2]	
HPS	70	6,300	30	8.28 [2]	
	100	9,500	43	9.55	
	150	16,000	62	11.36	
	200	22,000	79	13.41	
	250	29,000	102	15.60	
	310	37,000	124	18.41 [2]	
	400	50,000	163	21.37	
Flood, HPS	100	9,500	43	9.94 [2]	
	200	22,000	79	13.50 [2]	
	250	29,000	102	15.95	
	400	50,000	163	21.69	
Shoebox, HPS (bronze color, flat lens or drop lens, multi-volt)	70	6,300	30	9.09	
	100	9,500	43	10.52	
	150	16,500	62	12.58	
Special Acorn Type, HPS	100	9,500	43	13.42	
HADCO Victorian, HPS	150	16,500	62	14.91	
	200	22,000	79	16.64	
	250	29,000	102	18.89	
Early American Post-Top, HPS					
Black	100	9,500	43	10.51	
Special Types					
Cobrahead, Metal Halide	175	12,000	71	12.47	
Flood, Metal Halide	400	40,000	156	21.02	
Flood, HPS	750	105,000	285	35.60	(I)

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

SCHEDULE 15 (Continued)

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

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate Per Luminaire[1]	
Special Types (Continued)					
HADCO Independence, HPS	100	9,500	43	$12.77	(I)
	150	16,000	62	14.56	(I)
HADCO Capitol Acorn, HPS	100	9,500	43	17.09	(R)
	150	16,000	62	18.88	(R)
	200	22,000	79	20.48	(I)
	250	29,000	102	22.64	
HADCO Techtra, HPS	100	9,500	43	20.44	
	150	16,000	62	22.23	
	250	29,000	102	32.63	
KIM Archetype, HPS	250	29,000	102	20.23	
	400	50,000	163	25.76	
Holophane Mongoose, HPS	150	16,000	62	13.59	
	250	29,000	102	17.44	
	400	50,000	163	23.20	(I)

Rates for Area Light Poles

Type of Pole	Pole Length (feet)	Monthly Rate Per Pole
Wood, Standard	35 or less	$5.98
	55 or less	7.51
Wood, Painted for Underground	35 or less	6.99 [2]
Wood, Curved Laminated	30 or less	8.68 [2]
Aluminum, Regular	16	7.40
	25	12.03
	30	13.03
	35	14.33
Aluminum, Fluted Ornamental	14	14.07

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

SCHEDULE 32
SMALL NONRESIDENTIAL
STANDARD SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

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

MONTHLY RATE

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

Basic Charge			
Single Phase Service	$12.00		
Three Phase Service	$16.00		
Transmission and Related Services Charge	0.228	¢ per kWh	(I)
Distribution Charge			
First 5,000 kWh	3.541	¢ per kWh	
Over 5,000 kWh	0.817	¢ per kWh	
Energy Charge			
Standard Service	6.487	¢ per kWh	
or			
Time-of-Use (TOU) Portfolio Option (enrollment is necessary)			
On-Peak Period	11.135	¢ per kWh	
Mid-Peak Period	6.487	¢ per kWh	
Off-Peak Period	3.709	¢ per kWh	(I)
			(D)

* 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. **(C)**

The Daily Price will consist of:

- the Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Firm Index)
- plus 0.258¢ per kWh for wheeling **(I)**
- times a loss adjustment factor of 1.0826 **(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.

ADJUSTMENTS

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

SPECIAL CONDITIONS

1. Customers served under this schedule may at any time notify the Company of their intent to choose Direct Access Service. Notification must conform to the requirements established in Rule K.

2. Customers must enroll to receive service under any portfolio option. Customers may initially enroll or make one portfolio change per year without incurring the Portfolio Enrollment Charge as specified in Schedule 300.

SCHEDULE 32 (Continued)

SPECIAL CONDITIONS (Continued)

Pertaining to Renewable Portfolio Options

1. Service will become effective with the next regularly scheduled meter reading date provided the Customer has selected the option at least five days prior to their next scheduled meter read date. Absent the five-day notice, the change will become effective on the subsequent meter read date. Service may be terminated at the next regularly scheduled meter reading provided the Company has received notice two weeks prior to the meter read date. Absent the two-week notice, the termination will occur with the next subsequent meter reading date.

2. The Company will not accept enrollments from accounts with poor credit history. For the purposes of this rate schedule, poor credit history is defined as: a) having a time payment agreement that has not been kept current from month to month, b) having received two or more final disconnect notices in the past 12 months; or c) having been involuntarily disconnected in the past 12 months.

3. The Company will use reasonable efforts to acquire renewable energy, but does not guarantee the availability of renewable energy sources to serve Renewable Portfolio Options. The Company makes no representations as to the impact on the development of renewable resources or habitat restoration projects of Customer participation.

Pertaining to the TOU Option

1. Service may be terminated at the next regularly scheduled meter reading provided the Company has received notice two weeks prior to the meter read date. Absent the two-week notice, the termination will occur with the next subsequent meter reading date.

2. Participation requires a one year commitment by the Customer. Generally, if a Customer requests removal from the TOU Option, the Customer will be required to wait 12 months before re-enrolling. However, a Customer may request to reinstate service within 90 days of termination, in which case the Portfolio Enrollment Charge will be waived.

3. The Customer must take service at 120/240 volts or greater. Single phase 2-wire grounded service is not eligible because of special metering requirements.

4. The Customer must provide the Company access to the meter on a monthly basis. **(T)(D)**

SCHEDULE 32 (Concluded)

SPECIAL CONDITIONS (Continued)

Pertaining to the TOU Option (Continued)

5. At the end of the Customer's first 12 months of service under the TOU Option, the Company will calculate what the Customer would have paid under Standard Service and compare billings. If the Customer's Energy Charge billings (including all applicable supplemental adjustments) under the TOU Option exceeded the Standard Service Energy Charge (including all applicable supplemental adjustments) by more than 10%, the Company will issue the Customer a refund for the amount in excess of 10% either as a bill credit or refund check. No refund will be issued for Customers not meeting the 12-month requirement. **(T)** **(C)**

6. The Company will recover lost revenue from the TOU Option through Schedule 105. **(T)**

7. Billing will begin for any Customer on the next regularly scheduled meter reading date following the initialization meter reading made on a regularly scheduled meter reading date. **(T)**

8. The Company may choose to offer promotional incentives, including but not limited to rebates or coupons. **(T)**

TERM

Service under this schedule will not be for less than one year.

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

AVAILABLE

In all territory served by the Company.

APPLICABLE

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

MONTHLY RATE

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

Basic Charge			
Single Phase Service	$20.00		
Three Phase Service	$25.00		
Transmission and Related Services Charge	0.216	¢ per kWh	(I)
Distribution Charge	5.372	¢ per kWh	(I)
Energy Charge**			
On-Peak Period	6.756	¢ per kWh	(R)
Off-Peak Period	5.506	¢ 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 (Concluded)

DIRECT ACCESS DEFAULT SERVICE

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

Daily Price Option - The Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Firm Index) plus 0.258¢ 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 Quarterly Election Enrollment Window. **(I)**

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

Secondary Delivery Voltage 1.0826 **(R)**

ADJUSTMENTS

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

SPECIAL CONDITIONS

1. Service under this schedule will begin on the first day of the Customer’s regularly scheduled Billing Period.

2. In no case will the Company refund a Customer by retroactively adjusting the rate at which service was billed prior to the date the Customer begins service on this schedule.

(D)

TERM

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

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.

MONTHLY RATE

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

Basic Charge			
Summer Months**	$25.00		
Winter Months**	No Charge		
Transmission and Related Services Charge	0.260	¢ per kWh	(I)
Distribution Charge			
First 50 kWh per kW of Demand	5.219	¢ per kWh	
Over 50 kWh per kW of Demand	3.219	¢ per kWh	
Energy Charge***	7.335	¢ 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.

MONTHLY RATE

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

Basic Charge			
Summer Months**	$30.00		
Winter Months**	No Charge		
Transmission and Related Services Charge	0.254	¢ per kWh	(I)
Distribution Charge			
First 50 kWh per kW of Demand	3.276	¢ per kWh	
Over 50 kWh per kW of Demand	1.276	¢ per kWh	
Energy Charge***	7.227	¢ 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	$1,310.00	$1,040.00	$2,020.00	(I)
Transmission and Related Services Charge				
per kW of monthly On-Peak Demand	$0.88	$0.85	$0.84	(I)
Distribution Charges				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.77	$1.73	$1.73	(R)(I)(C)
Over 4,000 kW	$0.38	$0.34	$0.34	(R)(C)
per kW of monthly On-Peak Demand	$2.05	$1.98	$0.91	(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	0.427 ¢	0.403 ¢	0.389 ¢	(I)
Energy Charge				
per kWh	See Energy Charge Below			

* See Schedule 100 for applicable adjustments.

SCHEDULE 75 (Continued)

ENERGY CHARGE (Continued)

Baseline Energy (Continued)

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

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

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

Scheduled Maintenance Energy

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

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

Unscheduled Energy

Any Electricity provided to the Customer that does not qualify as Baseline Energy or Scheduled Maintenance Energy will be Unscheduled Energy and priced at an Hourly Rate consisting of the Dow Jones Mid-Columbia Hourly Firm Electricity Price Index (DJ-Mid-C Hourly Firm Index) plus 0.258 ¢ per kWh for wheeling, a 0.300¢ per kWh recovery factor, **(I)**
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	1.0337	
Primary Delivery Voltage	1.0484	**(R)**
Secondary Delivery Voltage	1.0826	**(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	(C)
Transmission and Related Services Charge per kW of Daily Economic Replacement Power (ERP) On-Peak Demand per day	$0.034	$0.033	$0.033	(I)
Daily ERP Demand Charge per kW of Daily ERP Demand during On-Peak hours per day**	$0.080	$0.077	$0.035	(I)(R)
System Usage Charge per kWh of ERP	0.427 ¢	0.403 ¢	0.389 ¢	(I)
Transaction Fee per Energy Needs Forecast (ENF)	$50.00	$50.00	$50.00	(C)
Energy Charge* per kWh of ERP	See below for ERP Pricing			

* See Schedule 100 for applicable adjustments.

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

SCHEDULE 76R (Continued)

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

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

ERP Pricing

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

Short-Notice ERP: The Short Notice ERP Energy Charge will be an Hourly Rate consisting of the Dow Jones Mid-Columbia Hourly Price Index (DJ-Mid-C Hourly Index) plus a 5% adder, which will not be less than 0.15¢ per kWh, plus 0.258¢ 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 0.258¢ 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 0.258¢ per kWh for wheeling, plus losses. At customer request and based on the submitted Monthly ENF, the Company will provide a price quote for the next full calendar month for the ENF commodity energy only amount specified by the customer at the time of the request. The Company will respond to the request with a quote within 4 hours or as otherwise mutually agreed to. Customer will accept or reject the quote within 30 minutes. Customer communication regarding a price quote will be in the manner agreed to by the Company and the Customer. The quote may incorporate reasonable premiums to reflect the additional cost of ENF amounts that are in nonstandard block sizes (i.e., other than multiples of 25 MW) and such premium will not be separately stated. **(I)**

SCHEDULE 76R (Continued)

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

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

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

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

Subtransmission Delivery Voltage	1.0337	
Primary Delivery Voltage	1.0484	**(R)**
Secondary Delivery Voltage	1.0826	**(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 Dow Jones Mid-Columbia Hourly Price Index (DJ-Mid-C Hourly Index), plus 0.258¢ per kWh for wheeling, plus losses. **(I)**
- For negative Imbalance Energy (where Customer receives less ERP than the ENF), the Imbalance Energy is multiplied by the Settlement Price of the DJ-Mid-C Hourly Index plus 0.258¢ per kWh for wheeling, plus losses. **(I)**

SCHEDULE 76R (Continued)

IMBALANCE ENERGY SETTLEMENT (Continued)

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

- For positive excess Imbalance Energy, the excess Imbalance Energy multiplied by the Settlement Price, which is the Dow Jones Mid-Columbia Hourly Price Index (DJ-Mid-C Hourly Index), plus 10%, plus 0.258¢ per kWh for wheeling, plus losses. **(I)**
- For negative excess Imbalance Energy, the excess Energy Imbalance is multiplied by the Settlement Price of the DJ-Mid-C Hourly Index, less 10%, plus 0.258¢ 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 77 (Continued)

PAYMENTS (Continued)

For the year of 2011, the reference fuel costs per MWh for an SCCT are: **(C)**

Jan 2011	Feb 2011	Jul 2011	Aug 2011	Sep 2011	Dec 2011
$64.28	$64.01	$54.20	$54.75	$55.03	$63.46

(C)
(I)

The Energy Reduction Payment rates will be updated annually by December 1st. Evaluation and settlement of the Energy Reduction Payment will occur within 60 days of the Firm Load Curtailment Event.

FIRM LOAD REDUCTION OPTION AND ELECTION

The Firm Load Reduction Options and terms are:

Firm Demand Reduction Options	Advance Notification Hours	Event Duration Consecutive Hours per Day
A	2	4
B	4	4

The Customer must select at the time of enrollment the applicable Firm Load Reduction Option to be in effect for the duration of the contract term.

FIRM LOAD REDUCTION

Firm Load Reduction will be measured as a reduction of Demand as specified in the Firm Load Reduction Agreement from a predetermined Daily Baseline Demand Profile during each hour of the Load Curtailment Event.

Daily Baseline Demand Profile

Daily Baseline Demand Profile is defined by measuring the participating Customer's Demand for each 15-minute interval over a minimum of the most recent 14 typical operational days prior to the Load Curtailment Event and combined into an average hourly Demand profile on an hour-by-hour basis.

Typical operational days exclude days that a Customer has participated in a Curtailment Event. If the Customer's energy usage is highly variable, the Company may, in collaboration with the Customer, develop at time of enrollment, an alternate method to determine baseline usage.

FIRM ENERGY REDUCTION

The Firm Energy Reduction Amount is the difference between the Customer's Baseline Energy Usage and the Customer's measured hourly energy usage during the Load Curtailment Event.

SCHEDULE 77 (Continued)

ENROLLMENT

The enrollment period for qualified Customers occurs annually from October 1st to October 15th (or the following business day if the 1st or the 15th falls on a weekend or holiday). Within five days of enrollment, the Company will confirm receipt of the PODID(s) the Customer intends to enroll under this schedule and will send a written contract to the Customer's representative. No later than October 30th (or the next business day if the 30th falls on a weekend or holiday), the Customer must sign a written Firm Load Reduction Agreement (FLRA) with the Company. The enrollment will be effective for the calendar year beginning January 1st, following the enrollment window. The Customer shall re-enroll annually in order to remain on this schedule.

SPECIAL CONDITIONS

1. Customers participating on the Company's Schedule 200 program may not use their on-site generation equipment for load reductions to meet load reduction commitments under this tariff. Customer on-site generation not under Schedule 200 must be permitted through applicable local, State and Federal agencies prior to its use to meet reduction commitments under this tariff.

2. Customers participating in Schedules 84, 86, 485, 489, 575, 583, 585 and 589 are not eligible. **(C)**

3. Firm Load Reduction by Schedule 75 Customers will not exceed the Customer's Baseline Demand as specified in the written service agreement between the Customer and the Company. Customer cannot use purchases under Schedule 76 to meet load reduction commitments under this tariff.

4. The Company is not responsible for any consequences to the participating Customer that results from the Firm Load Curtailment Event or the Customer's effort to reduce Energy in response to a Firm Load Curtailment Event. The Customer may not participate in this rider until the Company has installed metering that records usage in 15 minute intervals. The Customer will provide communication service to the meter if requested by the Company.

5. This tariff is not applicable when the Company requests or initiates load curtailment affecting a Customer PODID under system emergency conditions.

6. The Company will not cancel or shorten the duration of a Firm Curtailment Event once notification has been given without the consent of the Customer.

7. Monthly Reservation Payments and Energy Reduction Payments made to individual Customers under this tariff will be recovered from all Customers through the Company's Schedule 125 and Schedule 126 for the corresponding enrollment year.

8. The Company will file any adjustment to the Monthly Reservation Rate not less than two months prior to the annual enrollment period.

SCHEDULE 81
NONRESIDENTIAL
EMERGENCY DEFAULT SERVICE

AVAILABLE

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

APPLICABLE

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

MONTHLY RATE

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

ENERGY CHARGE DAILY RATE

The Energy Charge Daily Rate will be 125% of the Dow Jones Mid-Columbia Daily on- and off-peak Firm Electricity Price Index (DJ-Mid-C Firm Index) plus 0.258¢ per kWh for wheeling, plus **(I)** 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	1.0337	
Primary Delivery Voltage	1.0484	**(R)**
Secondary Delivery Voltage	1.0826	**(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) (C)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customers whose Demand has not exceeded 200 kW more than once in the preceding 13 months, or with seven months or less of service has not had a Demand exceeding 200 kW. (C) (C)

MONTHLY RATE

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

<u>Basic Charge</u>		(D)
Single Phase Service	$20.00	
Three Phase Service	$30.00	(I)
<u>Transmission and Related Services Charge</u>		
per kW of monthly Demand	$0.88	
<u>Distribution Charges</u>**		
The sum of the following:		
per kW of Facility Capacity		
First 30 kW	$3.00	
Over 30 kW	$2.50	(I)
per kW of monthly Demand	$1.83	(R)
<u>Energy Charge</u>		
Cost of Service Option per kWh	6.413 ¢	(I)
See below for Daily Pricing Option description.		(C)
<u>System Usage Charge</u>		
per kWh	0.380 ¢	(I) (D)

* 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.

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 **(T)**

Daily Price Option - The Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Firm Index) plus 0.258¢ 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 Quarterly Election Enrollment Window. **(I)**

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

(D)

Secondary Delivery Voltage	1.0826	**(R)**

(D)

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

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 83 (Continued)

ELECTION WINDOW

Quarterly Election Window

The Quarterly Election Window begins at 8:00 a.m. on February 15th, May 15th and August 15th (or the following business day if the 15th falls on a weekend or holiday). The Quarterly Election Windows 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.

During the Quarterly 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; for the May 15th election window, the election is effective July 1st and for the August 15th election window, the election is effective on October 1st. A Customer may not choose to move from an alternative option back to Cost of service during a Quarterly Election Window.

November Election Window

Enrollment for 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 Enrollment Windows 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.

During an Election Window, Customers may notify the Company of a choice to change service options using the Company's website, PortlandGeneral.com/business

MINIMUM CHARGE

The Minimum Charge will be the Basic, Distribution and Transmission 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 service facilities. **(C)**

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 84
LARGE NONRESIDENTIAL
LARGE LOAD SPLIT SERVICE RIDER OPTION

PURPOSE

The Large Load Split Service Rider Option allows a Customer to receive Direct Access Service for a percentage of its usage, while the remainder is served on the Cost of Service option.

APPLICABILITY

To Large Nonresidential Customers served on Schedule 85 or Schedule 89 that demonstrate the following: **(C)**

1) Usage in the most recent 12 months or, projected annual usage or where 12 months of usage history is not available, of at least 87,600,000 kWh (10 MWa) from one or more participating Points of Delivery (PODs);
2) An election to maintain at least 10 MWa usage on this option;
3) A Facility Capacity of at least 250 kW at each participating POD; and
4) An average non-coincident monthly load factor for the aggregated PODs participating of at least 60%, determined by the Company based on the historical usage information.

DESCRIPTION OF SERVICE OPTION

A Customer receiving service under this rider must elect 10% to 50% of eligible load to be served on Direct Access Service. All remaining load will be served by the Company.

DIRECT ACCESS BLOCK

The Direct Access Block is a fixed kWh served on Direct Access Service.

The Customer will choose the percentage of load to be served on Direct Access Service. The Company will determine the Direct Access Block by multiplying that percentage by the Customer's annual historical kWh usage for all participating PODs with the result divided by 8,760 hours, subject to the following limits:

- A Direct Access Block will not result in more than 50% of the annual historical usage.
- A POD may not have more than five consecutive days (or 120 hours) where the Direct Access Block is greater than the historical usage. When this occurs, the percentage that determines the Direct Access Block will be reduced for all of the Customer's PODs.

The Direct Access Block will remain unchanged for the calendar year [which may be less than 12 months if an Electricity Service Supplier (ESS) does not make a timely submittal of the required Direct Access Service Requests (DASRs)].

SCHEDULE 84 (Continued)

COMPANY SERVED LOAD

The Company Served Load is the difference between the Direct Access Block and the metered interval load data for each POD by hour. If actual usage in an hour is less than the Direct Access Block, the Company supplied Energy is deemed to be zero for the hour.

DIRECT ACCESS SERVICE

The Customer must arrange for an ESS to provide Direct Access Service for the Direct Access Block. The ESS is responsible for enrolling each participating POD in Direct Access Service and meeting all requirements defined in Rule G for timely DASR submittals. Beginning on January 1st, all participating PODs will be billed at the Daily Price until Direct Access Service commences for the participating PODs.

MONTHLY RATE

The Monthly Rate is the sum of the following charges:

Energy Charge

For the Company Served Load, the Cost of Service Monthly Energy Charge for the appropriate Delivery Voltage under Schedule 85 or Schedule 89 as applicable will apply. **(C)**

The Customer's ESS will bill separately for Energy provided for the Direct Access Block.

Other Charges

The following charges will be applied to the Customer's total usage for each POD: The Basic Charge, Transmission and Related Services Charge, Distribution Charge, System Usage Charge, Reactive and other applicable charges except the Energy Charge and including supplemental adjustments applied to each POD's total Energy, Demand, Facility Capacity and Reactive Demand.

A credit will be applied to the Direct Access Block billing for Transmission and Related Services. The credit will be equal to the Schedules 85 or 89 Transmission and Related Services Charge applied to the Direct Access Block Demand. **(C)**

SCHEDULE 84 (Concluded)

ENROLLMENT

The Company will provide a list of eligible PODs to Customers by September 15th of each calendar year (or the following business day if the 15th falls on a weekend or holiday).

By 5:00 p.m. on the last business day of September, the Customer must provide written notification to the Company verifying the following:

1) The Customer's intent to elect the service under this Rider.
2) A list of the PODs the Customer intends to enroll under this service option during the November Election Window (as defined in Schedules 85 and 89). **(C)**
3) The proposed percentage of load to be served on Direct Access Service. This designation will be used by the Company to determine the Direct Access Block.

By October 15th (or the following business day if the 15th falls on a weekend or holiday), the Company will confirm receipt of the election and the PODs the Customer intends to enroll. In order to receive service under this rider, the Customer must confirm enrollment during the November Election Window. After the Customer selection is confirmed during the November Election Window, the Company will provide the Customer with POD identification (PODID) numbers to be used by an ESS to enroll the Direct Access Block PODs in Direct Access. The Customer is responsible for furnishing this information to its selected ESS.

SET UP FEE

Customers notifying the Company of their intent to receive service under this rider will be charged a one-time non-refundable fee of $70 per each designated POD. This fee will be due with the Customer's written notification in September for a service election in November and service the following January.

TERM

All of the Customer's enrolled PODs will remain on this option for the entire calendar year and must be reenrolled annually.

SCHEDULE 85
LARGE NONRESIDENTIAL
STANDARD SERVICE
(201 – 1,000 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customers whose Demand has exceeded 200 kW but not exceeded 1,000 kW more than once in the preceding 13 months, or with seven months or less of service has exceeded 200 kW but not had a Demand exceeding 1,000 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	$400.00	$360.00
Transmission and Related Services Charge		
per kW of monthly On-Peak Demand	$0.88	$0.85
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 200 kW	$2.04	$1.97
Over 200 kW	$2.04	$1.97
per kW of monthly On-Peak Demand	$1.95	$1.88
Energy Charge		
On-Peak Period***	6.539 ¢	6.347 ¢
Off-Peak Period***	5.360 ¢	5.168 ¢
See below for Daily Pricing Option description.		
System Usage Charge		
per kWh	0.400 ¢	0.386 ¢

* 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.

NON COST OF SERVICE OPTION

Daily Price Option - The Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Firm Index) plus 0.258¢ 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 Quarterly Election Enrollment Window.

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

Primary Delivery Voltage	1.0484
Secondary Delivery Voltage	1.0826

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 85 (Continued)

ELECTION WINDOW

Quarterly Election Window

The Quarterly Election Window begins at 8:00 a.m. on February 15th, May 15th and August 15th (or the following business day if the 15th falls on a weekend or holiday). The Quarterly Election Windows 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.

During the Quarterly 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; for the May 15th election window, the election is effective July 1st and for the August 15th election window, the election is effective on October 1st. A Customer may not choose to move from an alternative option back to Cost of service during a Quarterly Election Window.

November Election Window

Enrollment for 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 Enrollment Windows 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.

During an Election Window, Customers may notify the Company of a choice to change service options using the Company's website, PortlandGeneral.com/business

MINIMUM CHARGE

The Minimum Charge will be the Basic, Distribution and Transmission 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 service facilities. The minimum Facility Capacity and Demand (in kW) will be 200 kW for primary voltage service.

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 85 (Concluded)

ADJUSTMENTS

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

TERM

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

SCHEDULE 86
DEMAND BUY BACK RIDER
NONRESIDENTIAL

PURPOSE

This rider is an optional, supplemental service that allows participating Customers an opportunity to voluntarily reduce their Electricity usage in return for a payment, at times and prices determined by the Company.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To qualifying Industrial, Commercial and General Service electric Customers served under Schedules 38, 83, 85, 89 and 99 who satisfy the conditions contained in this rider. Customers **(C)** must execute a Demand Buy Back Agreement prior to receiving service and have the capability to reduce not less than 250 kW aggregated from one or more points of delivery for each hour during a Buy Back Event.

BUY BACK CREDIT DETERMINATION

Energy Price

The Energy Price will be a price or prices quoted by the Company for a specified Buy Back Event, subject to requirements and other conditions described in Special Conditions.

Hourly Credit

Buy Back Amount (kWh) **X** Energy Price **=** Hourly Credit

The Hourly Credit is the amount owed to the Customer for each hour of the Buy Back Event. The Hourly Credit is determined by multiplying the Buy Back Amount by the Energy Price. The Hourly Credit will not be less than zero.

Buy Back Credit

The Buy Back Credit is the amount paid to the Customer for its Electricity reduction during a Buy Back Event and is the sum of each Hourly Credit during such event (minus any amounts owed as a result of failure to comply during an Extended Buy Back Event).

PAYMENTS

The Company will pay the Buy Back Credit to the Customer within 60 days of the Buy Back Event.

SCHEDULE 87 (Continued)

STANDARD BILL

The Standard Bill is calculated by applying the Annual Cost of Service Option under Schedule 89 to a CBL for each month of the year, excluding the Reactive Demand Charge and Adjustments identified in Schedule 100. If prices are revised, those changes will be reflected in the Customer's Standard Bill based on the CBL for a given month. Hourly Energy prices are applied only to kWh usage changes from the CBL in each hour.

CUSTOMER BASELINE LOAD (CBL)

The CBL is the Customer's hourly load for a 12-month period at typical levels of operation. It is developed based on the Customer's specific hourly load data or monthly billing data allocated to hours based on the consumption pattern agreed to by the Customer and the Company as typical of the Customer's operation.

Agreement to a CBL is a precondition for service under this schedule. The CBL is proprietary and will not be released to any other entity without the approval of the Customer and the Company. In order that the CBL reflect the Customer's Energy and Demand as accurately as possible, the Customer may request adjustments to the CBL for the following reasons:

1. The installation of permanent energy efficiency measures either as a participant in Energy Trust of Oregon programs or other verifiable conservation or technology improvement measures.
2. The addition or removal of equipment that results in a permanent change in the Customer's expected electricity consumption.

If the Customer leaves the program, he/she may not be allowed to return for a minimum of 12 months. A new CBL will be calculated in such cases based on the most recent usage. At a minimum, the CBL will be reviewed every three years and may be adjusted.

HOURLY ENERGY PRICE

Hourly Energy Prices are determined each day for the following day using Mid-Columbia Day Ahead Prices for on- and off-peak periods shaped to hourly prices based on the reported hourly Mid-Columbia prices from preceding days. The following charges will be added to the shaped hourly prices, 0.258¢ per kWh for wheeling, plus losses and the System Usage Charge as specified in Schedule 89. If prices are not reported for a particular day or days, the Company will estimate and shape prices from its hourly Energy price projections. **(I)**

In addition to the above charges, consumption of Energy above the CBL will be billed a 0.300¢ per kWh recovery factor. For consumption of Energy below the CBL, a 0.300¢ per kWh recovery factor will be subtracted from the Hourly Energy Price.

SCHEDULE 88
LOAD REDUCTION PROGRAM

PURPOSE

The Load Reduction Program is an optional, supplemental service that allows participating Customers an opportunity to voluntarily reduce Electricity usage to a Company-determined level during an Emergency Curtailment as described in Rule C(2)(B) in exchange for partial exemption from Emergency Curtailments.

AVAILABLE

In all territory served by the Company but total pledges will not exceed 5% of Company primary voltage circuits.

APPLICABLE

To an individual or a group of Large Nonresidential Customers receiving Electricity Service under Schedules 83, 85, 89, 485, 489, 583, 585 and/or 589 from one or more Point(s) of Delivery (PODs) but from the same dedicated primary circuit and able to reduce Baseline Usage from the primary circuit by a minimum of 15%. Customers applying as a group must be represented by a Lead Customer. A group may consist of multiple PODs under one Customer name that are all located on the same primary circuit. Participation is dependent upon satisfaction of all conditions contained in this schedule. **(C)**

BASELINE USAGE

The Baseline Usage is defined as the average usage for each hour for a minimum of 14 typical operational days prior to the Emergency Curtailment. Typical operational days exclude days that a Customer has participated in either an Emergency Curtailment or a Demand Buy Back Event (Schedule 86). Holidays and weekends will be excluded when determining the Baseline Usage except when the Emergency Curtailment includes weekends or holidays. The Customer may request that specific days be excluded from the 14-day baseline calculation upon demonstrating to the Company's satisfaction that the specific days are not similar days. The Company and Customer may mutually agree to use an alternate method to determine Baseline Usage when the Customer's usage is highly variable.

LOAD REDUCTION DETERMINATION

During an Emergency Curtailment, the individual Customer or group of Customers will be required to reduce Baseline Usage to a Company-determined Maximum Circuit Load (MCL). The MCL is the Customer's or group of Customer's Baseline Usage minus the necessary load reduction of 5, 10 or 15%.

SCHEDULE 89
LARGE NONRESIDENTIAL STANDARD SERVICE
(>1,000kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has exceeded 1,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 1,000 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	$1,310.00	$1,040.00	$2,020.00	(I)
Transmission and Related Services Charge				
per kW of monthly On-Peak Demand	$0.88	$0.85	$0.84	(I)
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.77	$1.73	$1.73	(R)(I)(C)
Over 4,000 kW	$0.38	$0.34	$0.34	(R) (C)
per kW of monthly On-Peak Demand	$2.05	$1.98	$0.91	(I) (R)
Energy Charge				
On-Peak Period***	6.324 ¢	6.136 ¢	6.054 ¢	(R)
Off-Peak Period***	5.145 ¢	4.957 ¢	4.875 ¢	(R)
See below for Daily Pricing Option description.				(C)
System Usage Charge				
Per kWh	0.427 ¢	0.403 ¢	0.389 ¢	(I)

* See Schedule 100 for applicable adjustments.

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

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

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 **(T)**

Daily Price Option - The Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Firm Index) plus 0.258¢ 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 Quarterly Election Enrollment Window. **(I)**

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

Subtransmission Delivery Voltage	1.0337	
Primary Delivery Voltage	1.0484	**(R)**
Secondary Delivery Voltage	1.0826	**(R)**
		(D)

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

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 luminaire based on the Monthly kWhs applicable to each installed luminaire.

Transmission and Related Services Charge	0.195 ¢ per kWh	**(I)**
Distribution Charge	3.654 ¢ per kWh	**(I)**
Energy Charge		
Cost of Service Option	5.540 ¢ per kWh	**(R)**

Daily Price Option – Available only to Customers with an average load of five MW or greater. In addition to the daily Energy price, the Customer will pay a Basic Charge of $75 per month to help offset the costs of billing this option. The daily Energy price for all kWh will be the Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Firm Index) plus 0.258¢ 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 Energy Rate 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 above applicable Daily Price by 1.0826. **(R)**

To begin service under this 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 [1] notice is received to return to the Cost of Service Option.

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

SCHEDULE 91 (Continued)

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Installation Labor Rate (1)	Straight Time	Overtime
	$117.00 per hour	$165.00 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	
Cobrahead Power Doors **	100	9,500	43	*	$2.56	(R)
	150	16,000	62	*	2.57	
	200	22,000	79	*	2.61	
	250	29,000	102	*	2.61	
	400	50,000	163	*	2.62	
Cobrahead	100	9,500	43	$5.23	2.75	
	150	16,000	62	5.25	2.76	
	200	22,000	79	5.66	2.80	
	250	29,000	102	5.69	2.79	
	400	50,000	163	5.73	2.83	
Flood	250	29,000	102	6.00	2.86	
	400	50,000	163	6.02	2.88	(R)

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

SCHEDULE 91 (Continued)

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

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	
Early American Post-Top	100	9,500	43	$5.71	$2.83	**(I)**
Shoebox (bronze color, flat lens, or drop lens, multi-volt)	70	6,300	30	5.84	2.82	**(R)**
	100	9,500	43	6.11	2.90	
	150	16,000	62	6.36	2.91	**(R)**

RATES FOR STANDARD POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B
Fiberglass, Black	20	$4.10	$0.14
Fiberglass, Bronze	30	5.47	0.18
Fiberglass, Gray	30	5.49	0.18
Wood, Standard	30 to 35	4.71	0.15
Wood, Standard	40 to 55	5.91	0.20

RATES FOR CUSTOM LIGHTING

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	
Special Acorn-Types						
HPS	100	9,500	43	$8.74	$3.23	**(I)**
HADCO Independence, HPS	100	9,500	43	8.16	3.24	
	150	16,000	62	8.17	3.25	**(I)**
HADCO Capitol Acorn, HPS	100	9,500	43	12.05	3.34	**(R)**
	150	16,000	62	12.06	3.35	
	200	22,000	79	12.06	3.35	
	250	29,000	102	12.06	3.35	**(R)**
Special Architectural Types						
HADCO Victorian, HPS	150	16,000	62	8.48	3.23	**(I)**
	200	22,000	79	8.61	3.32	
	250	29,000	102	8.69	3.32	**(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	
HADCO Techtra, HPS	100	9,500	43	$15.13	$4.21	(I)
	150	16,000	62	15.14	4.22	
	250	29,000	102	21.61	4.82	(I)
KIM Archetype, HPS	250	29,000	102	*	3.33	(R)
	400	50,000	163	*	3.32	(R)
HADCO Westbrooke, HPS	70	6,300	30	13.00	3.40	(I)
	100	9,500	43	12.96	3.39	
	150	16,000	62	12.97	3.40	
	200	22,000	79	13.11	3.40	
	250	29,000	102	13.11	3.40	(I)
Special Types						
Cobrahead, Metal Halide	175	12,000	71	5.50	2.95	
Flood, Metal Halide	400	40,000	156	6.02	3.00	(R)
Flood, HPS	750	105,000	285	8.33	3.92	
Holophane Mongoose, HPS	150	16,000	62	7.27	3.00	
	250	29,000	102	7.36	3.01	
	400	50,000	163	7.40	3.03	(R)

* Not offered.

RATES FOR CUSTOM POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Monthly Rates Option B
Aluminum, Regular	16	$5.83	$0.20
	25	9.48	0.32
	30	10.26	0.34
	35	11.29	0.38
Aluminum Davit	25	9.79	0.33
	30	10.44	0.35
	35	11.53	0.38
	40	14.08	0.47
Aluminum Double Davit	30	12.56	0.42

SCHEDULE 91 (Continued)

RATES FOR CUSTOM POLES (Continued)

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B
Aluminum, HADCO, Fluted Victorian Ornamental	14	$11.08	$0.37
Aluminum, HADCO, Non-Fluted Techtra Ornamental	18	19.81	0.65
Aluminum, HADCO, Fluted Ornamental	16	10.60	0.35
Aluminum, HADCO, Non-Fluted Ornamental Westbrooke	16	15.95	0.52
Aluminum, Painted Ornamental	35	27.35	0.90
Concrete, Ameron Post-Top	25	23.42	0.78
Fiberglass, HADCO, Fluted Ornamental Black	14	6.47	0.21
Fiberglass, Regular			
color may vary	22	3.17	0.11
color may vary	35	7.47	0.25
Fiberglass, Anchor Base, Gray	35	11.95	0.40
Fiberglass, Direct Bury with Shroud	18	6.20	0.21

SERVICE RATE FOR OBSOLETE LIGHTING

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

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	
Cobrahead, Mercury Vapor	100	4,000	39	*	*	
	175	7,000	66	$5.38	$2.71	(I)
	250	10,000	94	6.29	2.92	(R)
	400	21,000	147	5.45	2.79	
	1,000	55,000	374	6.23	3.08	(R)
Special Box Similar to GE "Space-Glo"						
HPS	70	6,300	30	8.71	2.83	(I)
Mercury Vapor	175	7,000	66	8.85	2.75	(R)

* Not offered.

SCHEDULE 91 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
Special Box, Anodized Aluminum Similar to GardCo Hub						
HPS	Twin 70	6,300	60	*	*	
	70	6,300	30	*	*	
	100	9,500	43	$8.50	$3.15	(R)
	150	16,000	62	*	3.16	(R)
	250	29,000	102	*	*	
	400	50,000	163	*	*	
Metal Halide	250	20,500	99	*	3.36	(I)
	400	40,000	156	*	3.74	(R)
Cobrahead, Dual Wattage, HPS						
70/100 Watt Ballast	100	9,500	43	*	2.73	(R)
100/150 Watt Ballast	100	9,500	43	*	2.73	|
100/150 Watt Ballast	150	16,000	62	*	2.74	(R)
Special Architectural Types						
KIM SBC Shoebox, HPS	150	16,000	62	*	3.65	(I)
Special Acorn-Type, HPS	70	6,300	30	8.48	2.83	(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	*	*	
Early American Post-Top, HPS						
Black	70	6,300	30	5.09	2.73	(R)
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	5.48	2.70	(R)

* Not offered.

SCHEDULE 91 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
Flood, HPS	70	6,300	30	$5.69	$2.80	(R)
	100	9,500	43	5.58	2.77	
	200	22,000	79	5.98	2.84	
Cobrahead, HPS						
Non-Power Door	70	6,300	30	5.18	2.79	
Power Door	310	37,000	124	6.40	3.14	(R)
Special Types Customer-Owned & Maintained						
Ornamental, HPS	100	9,500	43	*	*	
Twin Ornamental, HPS	Twin 100	9,500	86	*	*	
Compact Flourescent	28	N/A	12	*	*	

* Not offered.

RATES FOR OBSOLETE LIGHTING POLES

Type of Pole	Poles Length (feet)	Monthly Rates Option A	Monthly Rates Option B
Aluminum Post	30	$5.83	*
Bronze Alloy GardCo	12	*	$0.24
Concrete, Ornamental	35 or less	9.48	0.32
Steel, Painted Regular **	25	9.48	0.32
Steel, Painted Regular **	30	10.26	0.34
Steel, Unpainted 6-foot Mast Arm **	30	*	0.34
Steel, Unpainted 6-foot Davit Arm **	30	*	0.35
Steel, Unpainted 8-foot Mast Arm **	35	*	0.38
Steel, Unpainted 8-foot Davit Arm **	35	*	0.38
Wood, Laminated without Mast Arm	20	5.30	0.14
Wood, Laminated Street Light Only	20	4.10	*

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

SCHEDULE 91 (Continued)

RATES FOR OBSOLETE LIGHTING POLES (Continued)

Type of Pole	Poles Length (feet)	Monthly Rates Option A	Option B
Wood, Curved Laminated	30	$6.84	$0.25
Wood, Painted Underground	35	4.71	0.20
Wood, Painted Street Light Only	35	4.71	*

* Not offered.

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	
Special Architectural Types Including Philips QL Induction Lamp Systems						
HADCO Victorian, QL	85	6,000	32	$10.59	$2.05	(R)
	165	12,000	60	12.28	2.13	
HADCO Techtra, QL	85	6,000	32	13.97	2.18	
	165	12,000	60	14.68	2.22	(R)

ELECTION WINDOW

Quarterly Election Window

The Quarterly Election Window begins at 8:00 a.m. on February 15th, May 15th and August 15th (or the following business day if the 15th falls on a weekend or holiday). The Quarterly Election Windows 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.

During the Quarterly 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; for the May 15th election window, the election is effective July 1st and for the August 15th election window, the election is effective on October 1st. A Customer may not choose to move from an alternative option back to Cost of service during a Quarterly Election Window.

SCHEDULE 91 (Concluded)

SPECIAL CONDITIONS (Continued)

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

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

5. If Customer-owned (Option B) streetlighting equipment or poles are removed or relocated at the Customer's request, the Customer is responsible for the costs associated with the change.

6. If circuits or poles are removed or relocated at the Customer's request, the Customer is responsible for all associated costs for labor and materials incurred when fulfilling this request.

7. For Option C lights: When the Company provides the circuit, the Customer will incur a circuit charge of $1.38 per luminaire per month.

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

TERM

A Customer served under the Daily Pricing option may not choose service under another rate schedule until the end of the calendar year in which the pricing choice was made. **(C)**

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	0.199	¢ per kWh	**(I)**
Distribution Charge	2.563	¢ per kWh	**(I)**
Energy Charge	5.663	¢ per kWh	**(R)**

* See Schedule 100 for applicable adjustments.

ELECTION WINDOW

Quarterly Election Window

The Quarterly Election Window begins at 8:00 a.m. on February 15th, May 15th and August 15th (or the following business day if the 15th falls on a weekend or holiday). The Quarterly Election Windows 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.

During the Quarterly 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; for the May 15th election window, the election is effective July 1st and for the August 15th election window, the election is effective on October 1st. A Customer may not choose to move from an alternative option back to Cost of service during a Quarterly Election Window.

SCHEDULE 93
RECREATIONAL FIELD LIGHTING, PRIMARY VOLTAGE
STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers for recreational field lighting and related incidental lighting.

MONTHLY RATE

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

Basic Charge	$30.00		
Transmission and Related Services Charge	0.192	¢ per kWh	(I)
Distribution Charge	11.829	¢ per kWh	(I)
Energy Charge	5.470	¢ per kWh	(R)

* 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.

ADJUSTMENTS

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

SPECIAL CONDITION

The Customer's electrical equipment and its installation must be approved by the Company. All service under this schedule at any one location will be supplied through one meter.

TERM

Service under this schedule will not be for less than a one year.

SCHEDULE 94
COMMUNICATION DEVICES ELECTRICITY SERVICE RIDER

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments that have communication devices with energy requirements not exceeding 25 line watts per unit, that are installed on streetlights and, or traffic signals served under Schedules 91 and, or 92.

CHARACTER OF SERVICE

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

SERVICE

Service under this schedule will be based on an estimated total monthly kWh used, as determined by the Company, for all the Customer's devices. The estimated monthly usage will be updated as needed to reflect device installations or removals. Monthly kilowatt-hour usage will be computed on the basis of manufacturer's line wattage ratings of installed devices, with no allowances for outages.

MONTHLY RATE

The sum of the following charges per Point of Delivery:*

Transmission and Related Services Charge	0.199 ¢ per kWh	**(I)**
Distribution Charge	2.563 ¢ per kWh	**(I)**
Energy Charge	5.663 ¢ per kWh	**(R)**

* See Schedule 100 for applicable adjustments

The monthly kWh charge for service under this rider will be the number of units times estimated monthly usage determined using the following formula:

[((No. of Units x line watts per unit) x annual operating hours) / 1000] / 12

SCHEDULE 100
SUMMARY OF APPLICABLE ADJUSTMENTS

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

Schs.	102 (1)	105	106 (1)	108 (3)	109 (1)	110 (1)	111	115	121	122	123 (1)	125 (1)	126	128 (4)	129 (1)	130 (1)	133	140 (1)	**141**	142	**145**	(N)
7	x	x	x	x	x	x	x	x	x	x	x	x	x				x	x	x	x	x	
9			x	x				x												x		
12	x	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	x	
38	x	x	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	x	
49	x	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	x(2)	x(2)	x	x(2)	x(2)	x			x	x	x	x	x	
76R	x	x	x	x	x	x	x	x			x						x	x	x	x		
83	x	x	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	x	x	(N)
87	x(2)	x(2)	x	x	x	x	x	x	x(2)	x(2)	x	x	x(2)				x	x	x	x	x	
89	x	x	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	
93		x	x	x	x	x	x	x	x	x	x	x	x				x	x	x	x	x	
94		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		x(5)		x		x	x	x	x		(C)
489	x	x	x	x	x	x	x	x			x		x(5)		x		x	x	x	x		
515	x	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	x		x(5)	x			x	x	x	x	x	
538	x	x	x	x	x	x	x	x		x	x		x(5)	x		x	x	x	x	x	x	
549	x	x	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(2)	x			x	x	x	x	x	
576R	x	x	x	x	x	x	x	x			x						x	x	x	x		
583	x	x	x	x	x	x	x	x		x	x		x(5)	x		x	x	x	x	x	x	
585	x	x	x	x	x	x	x	x		x	x		x(5)	x		x	x	x	x	x	x	(N)
589	x	x	x	x	x	x	x	x		x	x		x(5)	x		x	x	x	x	x	x	
591		x	x	x	x	x		x		x	x		x(5)	x			x	x	x	x	x	
592		x	x	x	x	x		x		x	x		x(5)	x			x	x	x	x	x	
594		x	x	x	x	x		x		x	x		x	x			x	x	x	x	x	(N)

(1) Where applicable. (T)
(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 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 and 489). (C) (C)
(5) Not applicable to Customers where service was received for the entire calendar year that the Annual Power Cost Variance accrued. (T)

SCHEDULE 105
REGULATORY ADJUSTMENTS

PURPOSE

The purpose of this schedule is to reflect the effects of regulatory adjustments such as net gains from nonrecurring property transactions, and costs associated with the implementation of SB 1149, and miscellaneous nonrecurring items.

APPLICABLE

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

PART A – MISCELLANEOUS ADJUSTMENTS

Part A will be adjusted annually as necessary to recover nonrecurring Regulatory Adjustments.

PART B – LARGE NON-RESIDENTIAL LOAD TRUE-UP

Part B consists of costs associated with the Schedule 128 Large Nonresidential Load Shift True-up after the November 2008 open enrollment window.

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	0.000	0.000	0.000	¢ per kWh	(N)
12	0.000	0.000	0.000	¢ per kWh	
15	0.000	0.000	0.000	¢ per kWh	
32	0.000	0.000	0.000	¢ per kWh	
38	0.000	0.009	0.009	¢ per kWh	
47	0.000	0.000	0.000	¢ per kWh	
49	0.000	0.009	0.009	¢ per kWh	
75					
Secondary	0.000	0.009	0.009	¢ per kWh(1)	
Primary	0.000	0.009	0.009	¢ per kWh(1)	
Subtransmission	0.000	0.009	0.009	¢ per kWh(1)	

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

SCHEDULE 105 (Continued)

ADJUSTMENT RATES (Continued)

Schedule	Part A	Part B	Adjustment Rate		
76R					
Secondary	0.000	0.009	0.009	¢ per kWh	
Primary	0.000	0.009	0.009	¢ per kWh	
Subtransmission	0.000	0.009	0.009	¢ per kWh	
83	0.000	0.009	0.009	¢ per kWh	(C)
85					(N)
Secondary	0.000	0.009	0.009	¢ per kWh[(1)]	
Primary	0.000	0.009	0.009	¢ per kWh[(1)]	(N)
87					
Secondary	0.000	0.009	0.009	¢ per kWh[(1)]	
Primary	0.000	0.009	0.009	¢ per kWh[(1)]	
Subtransmission	0.000	0.009	0.009	¢ per kWh[(1)]	
89					
Secondary	0.000	0.009	0.009	¢ per kWh	
Primary	0.000	0.009	0.009	¢ per kWh	
Subtransmission	0.000	0.009	0.009	¢ per kWh	
91	0.000	0.009	0.009	¢ per kWh	
92	0.000	0.009	0.009	¢ per kWh	
93	0.000	0.009	0.009	¢ per kWh	
94	0.000	0.009	0.009	¢ per kWh	
485					(C)
Secondary	0.000	0.009	0.009	¢ per kWh	
Primary	0.000	0.009	0.009	¢ per kWh	
489					
Secondary	0.000	0.009	0.009	¢ per kWh	
Primary	0.000	0.009	0.009	¢ per kWh	
Subtransmission	0.000	0.009	0.009	¢ per kWh	

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

SCHEDULE 105 (Concluded)

ADJUSTMENT RATES (Continued)

Schedule	Part A	Part B	Adjustment Rate		
515	0.000	0.000	0.000	¢ per kWh	
532	0.000	0.000	0.000	¢ per kWh	
538	0.000	0.009	0.009	¢ per kWh	
549	0.000	0.009	0.009	¢ per kWh	
575					
Secondary	0.000	0.009	0.009	¢ per kWh(1)	
Primary	0.000	0.009	0.009	¢ per kWh(1)	
Subtransmission	0.000	0.009	0.009	¢ per kWh(1)	
576R					
Secondary	0.000	0.009	0.009	¢ per kWh	
Primary	0.000	0.009	0.009	¢ per kWh	
Subtransmission	0.000	0.009	0.009	¢ per kWh	
583	0.000	0.009	0.009	¢ per kWh	(C)
585					(N)
Secondary	0.000	0.009	0.009	¢ per kWh	
Primary	0.000	0.009	0.009	¢ per kWh(1)	(N)
589					
Secondary	0.000	0.009	0.009	¢ per kWh	
Primary	0.000	0.009	0.009	¢ per kWh	
Subtransmission	0.000	0.009	0.009	¢ per kWh	
591	0.000	0.009	0.009	¢ per kWh	
592	0.000	0.009	0.009	¢ per kWh	
594	0.000	0.009	0.009	¢ per kWh	

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

SCHEDULE 109
ENERGY EFFICIENCY FUNDING ADJUSTMENT

PURPOSE

To fund the acquisition of additional Energy Efficiency Measures (EEMs) for the benefit of the Company's customers pursuant to the Oregon Renewable Energy Act, Section 46 through programs administered by the Energy Trust of Oregon (ETO).

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 (SDC). Customers so exempted will not be charged for nor directly benefit from the energy efficiency measures funded by this schedule.

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.

DISBURSEMENT OF FUNDS

All funds collected under this schedule less an allowance for uncollectible expenses will be distributed to the ETO on a monthly basis.

ENERGY EFFICIENCY ADJUSTMENT

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

Schedule	Adjustment Rate	
7	0.147 ¢ per kWh	(N)
12	0.147 ¢ per kWh	
15	0.256 ¢ per kWh	
32	0.138 ¢ per kWh	
38	0.145 ¢ per kWh	
47	0.161 ¢ per kWh	
49	0.115 ¢ per kWh	

SCHEDULE 109 (Continued)

ENERGY EFFICIENCY ADJUSTMENT (Continued)

Schedule	Adjustment Rate	
75		
Secondary	0.100 ¢ per kWh	
Primary	0.100 ¢ per kWh	
Subtransmission	0.100 ¢ per kWh	
76R		
Secondary	0.100 ¢ per kWh	
Primary	0.100 ¢ per kWh	
Subtransmission	0.100 ¢ per kWh	
83	0.114 ¢ per kWh	(C)
85		(N)
Secondary	0.114 ¢ per kWh	
Primary	0.114 ¢ per kWh	(N)
87		
Secondary	0.100 ¢ per kWh	
Primary	0.100 ¢ per kWh	
Subtransmission	0.100 ¢ per kWh	
89		
Secondary	0.100 ¢ per kWh	
Primary	0.100 ¢ per kWh	
Subtransmission	0.100 ¢ per kWh	
91	0.228 ¢ per kWh	
92	0.115 ¢ per kWh	
93	0.223 ¢ per kWh	
94	0.115 ¢ per kWh	(C)
485		
Secondary	0.114 ¢ per kWh	
Primary	0.114 ¢ per kWh	

SCHEDULE 109 (Concluded)

ENERGY EFFICIENCY ADJUSTMENT (Continued)

Schedule	Adjustment Rate	
489		
Secondary	0.100 ¢ per kWh	
Primary	0.100 ¢ per kWh	
Subtransmission	0.100 ¢ per kWh	
515	0.256 ¢ per kWh	
532	0.138 ¢ per kWh	
538	0.145 ¢ per kWh	
549	0.115 ¢ per kWh	
575		
Secondary	0.100 ¢ per kWh	
Primary	0.100 ¢ per kWh	
Subtransmission	0.100 ¢ per kWh	
576R		
Secondary	0.100 ¢ per kWh	
Primary	0.100 ¢ per kWh	
Subtransmission	0.100 ¢ per kWh	
583	0.114 ¢ per kWh	**(C)**
585		**(N)**
Secondary	0.114 ¢ per kWh	
Primary	0.114 ¢ per kWh	**(N)**
589		
Secondary	0.100 ¢ per kWh	
Primary	0.100 ¢ per kWh	
Subtransmission	0.100 ¢ per kWh	
591	0.228 ¢ per kWh	
592	0.115 ¢ per kWh	
594	0.115 ¢ per kWh	

TERM

This Schedule will terminate on December 31, 2012, subject to review by the Company completed by September 2009 regarding the efficacy of continued funding under this schedule for calendar years 2010 through 2012.

SCHEDULE 110 (Continued)

ENERGY EFFICIENCY CUSTOMER SERVICE ADJUSTMENT

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

Schedule	Adjustment Rate	
7	0.003 ¢ per kWh	
12	0.003 ¢ per kWh	**(N)**
15	0.006 ¢ per kWh	
32	0.003 ¢ per kWh	
38	0.003 ¢ per kWh	
47	0.003 ¢ per kWh	
49	0.002 ¢ per kWh	
75		
Secondary	0.002 ¢ per kWh	
Primary	0.002 ¢ per kWh	
Subtransmission	0.002 ¢ per kWh	
76R		
Secondary	0.002 ¢ per kWh	
Primary	0.002 ¢ per kWh	
Subtransmission	0.002 ¢ per kWh	**(C)**
83	0.003 ¢ per kWh	**(N)**
85		
Secondary	0.003 ¢ per kWh	
Primary	0.003 ¢ per kWh	**(N)**
87		
Secondary	0.005 ¢ per kWh	
Primary	0.005 ¢ per kWh	
Subtransmission	0.005 ¢ per kWh	
89		
Secondary	0.002 ¢ per kWh	
Primary	0.002 ¢ per kWh	
Subtransmission	0.002 ¢ per kWh	
91	0.005 ¢ per kWh	
92	0.002 ¢ per kWh	

SCHEDULE 110 (Continued)

ENERGY EFFICIENCY CUSTOMER SERVICE ADJUSTMENT (Continued)

Schedule	Adjustment Rate	
93	0.005 ¢ per kWh	
94	0.002 ¢ per kWh	(C)
485		
Secondary	0.003 ¢ per kWh	
Primary	0.003 ¢ per kWh	
489		
Secondary	0.002 ¢ per kWh	
Primary	0.002 ¢ per kWh	
Subtransmission	0.002 ¢ per kWh	
515	0.006 ¢ per kWh	
532	0.003 ¢ per kWh	
538	0.003 ¢ per kWh	
549	0.002 ¢ per kWh	
575		
Secondary	0.002 ¢ per kWh	
Primary	0.002 ¢ per kWh	
Subtransmission	0.002 ¢ per kWh	
576R		
Secondary	0.002 ¢ per kWh	
Primary	0.002 ¢ per kWh	
Subtransmission	0.002 ¢ per kWh	(C)
583	0.003 ¢ per kWh	(N)
585		
Secondary	0.003 ¢ per kWh	(N)
Primary	0.003 ¢ per kWh	
589		
Secondary	0.002 ¢ per kWh	
Primary	0.002 ¢ per kWh	
Subtransmission	0.002 ¢ per kWh	

SCHEDULE 111
ADVANCED METERING INFRASTRUCTURE

PURPOSE

To recover from Customers the revenue requirement impact of newly installed Advanced Metering Infrastructure (AMI), less Operations and Maintenance (O & M) cost savings, plus the accelerated depreciation for meters that AMI will replace.

APPLICABLE

To all bills for electric service calculated under all rate schedules listed below.

ADJUSTMENT RATE

The Adjustment Rates, applicable for service on and after June 1, 2008, will be:

Schedule	Adjustment Rate		
7	0.000	¢ per kWh	(R) (N)
12	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	
76R			
Secondary	0.000	¢ per kWh	
Primary	0.000	¢ per kWh	
Subtransmission	0.000	¢ per kWh	(R)(C)
83	0.000	¢ per kWh	(N)
85			
Secondary	0.000	¢ per kWh	
Primary	0.000	¢ per kWh	(N)

SCHEDULE 111 (Continued)

ADJUSTMENT RATES (Continued)

Schedule	Adjustment Rate		
87			(R)
Secondary	0.000	¢ per kWh	
Primary	0.000	¢ per kWh	
Subtransmission	0.000	¢ per kWh	
89			
Secondary	0.000	¢ per kWh	
Primary	0.000	¢ per kWh	
Subtransmission	0.000	¢ per kWh	
93	0.000	¢ per kWh	(C)
485			
Secondary	0.000	¢ per kWh	
Primary	0.000	¢ per kWh	
489			
Secondary	0.000	¢ per kWh	
Primary	0.000	¢ per kWh	
Subtransmission	0.000	¢ per kWh	
532	0.000	¢ per kWh	
538	0.000	¢ per kWh	
549	0.000	¢ per kWh	
575			
Secondary	0.000	¢ per kWh	
Primary	0.000	¢ per kWh	
Subtransmission	0.000	¢ per kWh	
576R			
Secondary	0.000	¢ per kWh	
Primary	0.000	¢ per kWh	(R)
Subtransmission	0.000	¢ per kWh	

SCHEDULE 111 (Concluded)

ADJUSTMENT RATES (Continued)

583	0.000	¢ per kWh	(R)(C)
585			
Secondary	0.000	¢ per kWh	(N)
Primary	0.000	¢ per kWh	(N)
589			
Secondary	0.000	¢ per kWh	(R)
Primary	0.000	¢ per kWh	
Subtransmission	0.000	¢ per kWh	(R)

SPECIAL CONDITIONS

1. This Schedule will terminate within six months or less of the effective date if Systems Acceptance Testing is not successful or alternatively if the Company does not commence mass deployment of meters within 75 days of completion of Systems Acceptance Testing.

2. This Schedule may be temporarily suspended in order to resolve specific issues identified during Systems Acceptance Testing. The Company must file an application to suspend at least 45 days before the termination deadline specified in Special Condition 1.

TERM

This adjustment schedule will terminate December 31, 2010.

SCHEDULE 121
SELECTIVE WATER WITHDRAWAL ADJUSTMENT

PURPOSE

This schedule recovers the fixed generation revenue requirement of the Company's Selective Water Withdrawal project on the Deschutes River located at the Round Butte Dam. Approval of this tariff adjustment will be considered a Commission revision of the Company's ratio of net revenues to gross revenues and effective tax rate for purposes of OAR 860-22-0041.

AVAILABLE

In all territory served by the Company

APPLICABLE

To all bills for Electricity Service served under the following rate schedules 7, 12, 15, 32, 38, 47, 49, 75, 83, 85, 87, 89, 91, 92, 93 and 94. (C)

ADJUSTMENT RATE

Schedule		Adjustment Rate		
7		0.000	¢ per kWh	(R)
12		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	(C)(R)
85				(N)
	Secondary	0.000	¢ per kWh	
	Primary	0.000	¢ per kWh	(N)
87				(R)
	Secondary	0.000	¢ per kWh	
	Primary	0.000	¢ per kWh	
	Subtransmission	0.000	¢ per kWh	
89				
	Secondary	0.000	¢ per kWh	
	Primary	0.000	¢ per kWh	
	Subtransmission	0.000	¢ per kWh	(R)

SCHEDULE 121 (Concluded)

ADJUSTMENT RATE (Continued)

Schedule	Adjustment Rate	
91	0.000 ¢ per kWh	(R)
92	0.000 ¢ per kWh	
93	0.000 ¢ per kWh	
94	0.000 ¢ per kWh	(R)

SPECIAL CONDITIONS

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

2. The rates in this schedule will be added to the applicable rate schedules' Cost of Service Energy Charges for purposes of calculating the Schedule 128 Transition Adjustment.

3. Collections under this schedule will terminate at such time as the costs are included in base rates.

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 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).

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all bills for Electricity Service except Schedules 9, 76, 485, 489, and 576. This schedule is not applicable to direct access customers after December 31, 2010. **(C)**

ADJUSTMENT RATE

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

Schedule			
7	0.227	¢ per kWh	
12	0.227	¢ per kWh	**(N)**
15	0.211	¢ per kWh	
32	0.227	¢ per kWh	
38	0.229	¢ per kWh	
47	0.210	¢ per kWh	
49	0.211	¢ per kWh	
75			
Secondary	0.226	¢ per kWh	
Primary	0.215	¢ per kWh	
Subtransmission	0.209	¢ per kWh	
83	0.225	¢ per kWh	**(C)**
85			**(N)**
Secondary	0.225	¢ per kWh	|
Primary	0.218	¢ per kWh	**(N)**

SCHEDULE 122 (Continued)

ADJUSTMENT RATE (Continued)

Schedule			
87			
Secondary	0.226	¢ per kWh	
Primary	0.215	¢ per kWh	
Subtransmission	0.209	¢ per kWh	
89			
Secondary	0.226	¢ per kWh	
Primary	0.215	¢ per kWh	
Subtransmission	0.209	¢ per kWh	
91	0.211	¢ per kWh	
92	0.221	¢ per kWh	
93	0.225	¢ per kWh	
94	0.221	¢ per kWh	
515	0.211	¢ per kWh	
532	0.227	¢ per kWh	
538	0.229	¢ per kWh	
549	0.211	¢ per kWh	
575			
Secondary	0.226	¢ per kWh	
Primary	0.215	¢ per kWh	
Subtransmission	0.209	¢ per kWh	
583	0.225	¢ per kWh	(C)
585			(N)
Secondary	0.225	¢ per kWh	
Primary	0.218	¢ per kWh	(N)
589			
Secondary	0.226	¢ per kWh	
Primary	0.215	¢ per kWh	
Subtransmission	0.209	¢ per kWh	
591	0.211	¢ per kWh	
592	0.221	¢ per kWh	
594	0.221	¢ per kWh	

SCHEDULE 123
SALES NORMALIZATION 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 5.842 cents/kWh for Schedule 7 **(I)**
and 5.593 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 $51.29 per month for Schedule 7 and $79.50 per month for Schedules 32 and **(I)**
532 to the numbers of active Schedule 7 and Schedule 32 and 532 Customers, respectively, for each month.

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

SCHEDULE 123 (Continued)

NONRESIDENTIAL LOST REVENUE RECOVERY ADJUSTMENT (LRRA)

The Nonresidential Lost Revenue Recovery Adjustment is applicable to all customers except those served under Schedules 7, 32 and 532 or as otherwise exempted above. Nonresidential Lost Revenue Recovery amounts will be equal to the reduction in distribution, transmission, and fixed generation revenues due to the reduction in kWh sales as reported to the Company by the Energy Trust of Oregon, resulting from EEMs implemented during prior calendar years attributable to EEM funding incremental to Schedule 108, adjusted for EEM program kWh savings incorporated into the test year load forecast used to determine base rates. 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 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 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 the reduction in kWh sales resulting from ETO-reported EEMs and 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 4.011 cents per **(I)**
kWh.

SNA and LRRA BALANCING ACCOUNTS

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

SCHEDULE 123 (Continued)

SALES NORMALIZATION ADJUSTMENT (SNA)

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

Schedule	Adjustment Rate		
7	0.000	¢ per kWh	
12	0.000	¢ per kWh	(N)
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	
76R			
Secondary	0.000	¢ per kWh	
Primary	0.000	¢ per kWh	
Subtransmission	0.000	¢ per kWh	
83	0.000	¢ per kWh	(C)
85			(N)
Secondary	0.000	¢ per kWh	
Primary	0.000	¢ per kWh	(N)
87			
Secondary	0.000	¢ per kWh	
Primary	0.000	¢ per kWh	
Subtransmission	0.000	¢ per kWh	
89			
Secondary	0.000	¢ per kWh	
Primary	0.000	¢ per kWh	
Subtransmission	0.000	¢ per kWh	

SCHEDULE 123 (Continued)

SALES NORMALIZATION ADJUSTMENT (SNA) (Continued)

Schedule	Adjustment Rate		
91	0.000	¢ per kWh	(M)
92	0.000	¢ per kWh	
93	0.000	¢ per kWh	
94	0.000	¢ per kWh	(M)
485			(C)
Secondary	0.000	¢ per kWh	
Primary	0.000	¢ per kWh	
489			
Secondary	0.000	¢ per kWh	
Primary	0.000	¢ per kWh	
Subtransmission	0.000	¢ per kWh	
515	0.000	¢ per kWh	
532	0.000	¢ per kWh	
538	0.000	¢ per kWh	
549	0.000	¢ per kWh	
575			
Secondary	0.000	¢ per kWh	
Primary	0.000	¢ per kWh	
Subtransmission	0.000	¢ per kWh	
576R			
Secondary	0.000	¢ per kWh	
Primary	0.000	¢ per kWh	
Subtransmission	0.000	¢ per kWh	
583	0.000	¢ per kWh	(C)
585			(N)
Secondary	0.000	¢ per kWh	
Primary	0.000	¢ per kWh	(N)

(T)

SCHEDULE 123 (Continued)

SALES NORMALIZATION ADJUSTMENT (SNA) (Continued) (M)

Schedule	Adjustment Rate
589	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
591	0.000 ¢ per kWh
592	0.000 ¢ per kWh
594	0.000 ¢ per kWh

(M)

TIME AND MANNER OF FILING

Commencing in 2010, the Company will submit to the Commission the following information by April 1 of each year:

1. The proposed price changes to this Schedule to be effective on June 1st of the submittal year based on a) the amount in the SNA Balancing Account at the end of the 12-month period commencing on February 1, 2009, and 2010, and at the end of each succeeding (C) calendar year and b) the amount in the LRRA Balancing Account at the end of the (C) previous calendar year.

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

3. The status of the SNA and LRRA Balancing Accounts.

SCHEDULE 123 (Concluded)

SPECIAL CONDITIONS (M)

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

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

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

(D)

(M)

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 bills for Electricity Service served under the following rate schedules 7, 12, 15, 32, 38, 47, **(C)**
49, 75, 83, 85, 87, 89, 91, 92, 93 and 94. **(C)**

NET VARIABLE POWER COSTS

Net Variable Power Costs (NVPC) are the power costs for energy generated and purchased. NVPC are the net cost of fuel, fuel 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.
- Forward market prices for both gas and electricity.
- Projected loads.
- Contracts for the purchase or sale of power and fuel.
- Thermal plant variable operation and maintenance. **(N)**
- Changes in hedges, options, and other financial instruments used to serve retail load.
- Transportation contracts and other fixed transportation costs.
- No other changes or updates will be made in the annual filings under this schedule.

CHANGES IN NET VARIABLE POWER COSTS

Changes in NVPC for purposes of rate determination under this schedule are the projected NVPC as determined in the Annual Power Cost Update less the NVPC revenues that would occur at the NVPC prices determined in the Company's most recent general rate case, adjusted for a revenue sensitive cost factor of 1.0352. **(I)**

SCHEDULE 125 (Continued)

FILING AND EFFECTIVE DATE

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

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

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

RATE ADJUSTMENT

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

ADJUSTMENT RATES

Schedule		Part A ¢ per kWh	
7		0.000	**(I)**
12		0.000	**(N)**
15		0.000	
32		0.000	
38	Large Nonresidential	0.000	
47		0.000	
49		0.000	
75	Secondary	0.000 [1]	
	Primary	0.000 [1]	
	Subtransmission	0.000 [1]	
83		0.000	**(I)(C)**
85	Secondary	0.000	**(N)**
	Primary	0.000	**(N)**
87	Secondary	0.000	**(I)**
	Primary	0.000	
	Subtransmission	0.000	**(I)**

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

SCHEDULE 125 (Concluded)

ADJUSTMENT RATES (Continued)

Schedule		Part A ¢ per kWh	
89	Secondary	0.000	(I)
	Primary	0.000	
	Subtransmission	0.000	
91		0.000	
92		0.000	
93		0.000	
94		0.000	(I)

SPECIAL CONDITIONS

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

SCHEDULE 126
ANNUAL POWER COST VARIANCE MECHANISM

PURPOSE

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

APPLICABLE

To all Customers for Electricity Service except those who were served on Schedule 76R and 576R, 485, 489, 515, 532, 538, 549, 583, 585, 589, 591, 592 and 594, or served under Schedules 83, 85 or 89 Daily Price Option for the entire calendar year that the Annual Power Cost Variance accrued. Customers served on Schedules 538, 583, 585, 589, 591 and 592 who received the Schedule 128 Balance of Year Transition Adjustment will be subject to this adjustment. (C) | (C)

ANNUAL POWER COST VARIANCE (T)

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

POWER COST VARIANCE ACCOUNT

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

Any balance in the PCV Account will be amortized to rates over a period determined by the Commission. Annually, the Company will propose to the Commission PCV Adjustment Rates that will amortize the PCV to rates over a period recommended by the Company. The amount accruing to Customers, whether positive or negative, will be multiplied by a revenue sensitive factor of 1.0352 to account for franchise fees, uncollectibles, and OPUC fees. (I)

EARNINGS TEST

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

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 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.

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 594 after the November update for the applicable year.

Negative Annual Power Cost Deadband

The Negative Annual Power Cost Deadband is ($10.0 million). **(C)**

Positive Annual Power Cost Deadband

The Positive Annual Power Cost Deadband is $10.0 million. **(C)**

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, fuel 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, and 91 **(C)** Energy pricing options other than Cost of Service and the Energy Charge revenues from the Market Based Pricing Option from Schedules 485 and 489 as an offset to **(C)** NVPC.
- NVPC shall be adjusted as needed to comply with Order 07-015 that states that ancillary services, the revenues from sales as well as the costs from the services, should also be taken into account in the mechanism.
- Actual NVPC will be increased to include the value of the energy associated with those Customers that received the Schedule 128 Balance of Year Transition Adjustment for the period during the year that the Customers received the Schedule 128 adjustment.

ADJUSTMENT AMOUNT

The amount accruing to the Power Cost Variance Account, whether positive or negative will be multiplied by a revenue sensitive factor of 1.0352 to account for franchise fees, uncollectables, and **(I)** 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.

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	(0.007) ¢ per kWh	**(N)**
12	(0.007) ¢ per kWh	
15	(0.007) ¢ per kWh	
32	(0.007) ¢ per kWh	
38	(0.007) ¢ per kWh	
47	(0.007) ¢ per kWh	
49	(0.007) ¢ per kWh	
75		
Secondary	(0.007) ¢ per kWh(1)	
Primary	(0.007) ¢ per kWh(1)	
Subtransmission	(0.007) ¢ per kWh(1)	
83	(0.007) ¢ per kWh	**(C)**
85		**(N)**
Secondary	(0.007) ¢ per kWh	
Primary	(0.007) ¢ per kWh(1)	**(N)**
87		
Secondary	(0.007) ¢ per kWh(1)	
Primary	(0.007) ¢ per kWh(1)	
Subtransmission	(0.007) ¢ per kWh(1)	
89		
Secondary	(0.007) ¢ per kWh	
Primary	(0.007) ¢ per kWh	
Subtransmission	(0.007) ¢ 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 126 (Continued)

POWER COST VARIANCE RATES (Continued)

Schedule	Adjustment Rate	
91	(0.007) ¢ per kWh	
92	(0.007) ¢ per kWh	
93	(0.007) ¢ per kWh	
94	(0.007) ¢ per kWh	
485		(C)
Secondary	(0.007) ¢ per kWh(2)	
Primary	(0.007) ¢ per kWh(2)	
489		
Secondary	(0.007) ¢ per kWh(2)	
Primary	(0.007) ¢ per kWh(2)	
Subtransmission	(0.007) ¢ per kWh(2)	
515	(0.007) ¢ per kWh(2)	
532	(0.007) ¢ per kWh(2)	
538	(0.007) ¢ per kWh(2)	
549	(0.007) ¢ per kWh(2)	
575		
Secondary	(0.007) ¢ per kWh(1)	
Primary	(0.007) ¢ per kWh(1)	
Subtransmission	(0.007) ¢ per kWh(1)	
583	(0.007) ¢ per kWh(2)	(C)
585	(0.007) ¢ per kWh(2)	(N)
Seconday	(0.007) ¢ per kWh(2)	
Primary	(0.007) ¢ per kWh(2)	(N)
589		
Secondary	(0.007) ¢ per kWh(2)	
Primary	(0.007) ¢ per kWh(2)	
Subtransmission	(0.007) ¢ per kWh(2)	
591	(0.007) ¢ per kWh(2)	
592	(0.007) ¢ per kWh(2)	
594	(0.007) ¢ 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 or 91; or Direct Access service on Schedules 515, 532, 538, 549, 575, 583, 585, 589, 591, 592, 594. This Schedule is not applicable to Customers served on Schedules 485 and 489. **(C)** **(C)**

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 2011, the Annual Short-Term Transition Adjustment Rate will be applied to their bills for service effective on and after January 1, 2011: **(C)** **(C)**

Schedule		Annual ¢ per kWh [(1)]	
32		0.565	**(R)**
38		0.310	
75	Secondary On-Peak	(0.035) [(2)]	
	Secondary Off-Peak	0.089 [(2)]	
	Primary On-Peak	0.005 [(2)]	
	Primary Off-Peak	0.070 [(2)]	
	Subtransmission On-Peak	0.011 [(2)]	
	Subtransmission Off-Peak	0.049 [(2)]	
83		0.517	**(R)(C)**
85	Secondary On-Peak	0.199	**(N)**
	Secondary Off-Peak	0.301	
	Primary On-Peak	0.213	
	Primary Off-Peak	0.279	**(N)**

(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 On-Peak	(0.035)	(R)
	Secondary Off-Peak	0.089	
	Primary On-Peak	0.005	
	Primary Off-Peak	0.070	
	Subtransmission On-Peak	0.011	
	Subtransmission Off-Peak	0.049	
91		0.026	
515		0.026	
532		0.565	
538		0.310	(R)
549		1.671	(I)
575	Secondary On-Peak	(0.035) [2]	(R)
	Secondary Off-Peak	0.089 [2]	
	Primary On-Peak	0.005 [2]	
	Primary Off-Peak	0.070 [2]	
	Subtransmission On-Peak	0.011 [2]	
	Subtransmission Off-Peak	0.049 [2]	(R)
583		0.517	(C)
585	Secondary On-Peak	0.199	(N)
	Secondary Off-Peak	0.301	
	Primary On-Peak	0.213	
	Primary Off-Peak	0.279	(N)
589	Secondary On-Peak	(0.035)	(R)
	Secondary Off-Peak	0.089	
	Primary On-Peak	0.005	
	Primary Off-Peak	0.070	
	Subtransmission On-Peak	0.011	
	Subtransmission Off-Peak	0.049	
591		0.026	
592		(0.116)	
594		(0.116)	(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 will be posted by the Company two months 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 (Continued)

Second Quarter – April 1st Balance of Year Adjustment Rate [1]

Schedule		¢ per kWh [2]	
38		0.000	
75	Secondary On-Peak	0.000 [3]	
	Secondary Off-Peak	0.000 [3]	
	Primary On-Peak	0.000 [3]	
	Primary Off-Peak	0.000 [3]	
	Subtransmission On-Peak	0.000 [3]	
	Subtransmission Off-Peak	0.000 [3]	
83		0.000	(C)
85	Secondary On-Peak	0.000 [3]	(N)
	Secondary Off-Peak	0.000 [3]	
	Primary On-Peak	0.000 [3]	
	Primary Off-Peak	0.000 [3]	(N)
89	Secondary On-Peak	0.000	
	Secondary Off-Peak	0.000	
	Primary On-Peak	0.000	
	Primary Off-Peak	0.000	
	Subtransmission On-Peak	0.000	
	Subtransmission Off-Peak	0.000	
91		0.000	
538		0.000	
575	Secondary On-Peak	0.000 [3]	
	Secondary Off-Peak	0.000 [3]	
	Primary On-Peak	0.000 [3]	
	Primary Off-Peak	0.000 [3]	
	Subtransmission On-Peak	0.000 [3]	
	Subtransmission Off-Peak	0.000 [3]	
583		0.000	(C)
585	Secondary On-Peak	0.000 [3]	(N)
	Secondary Off-Peak	0.000 [3]	
	Primary On-Peak	0.000 [3]	
	Primary Off-Peak	0.000 [3]	(N)
589	Secondary On-Peak	0.000	
	Secondary Off-Peak	0.000	
	Primary On-Peak	0.000	
	Primary Off-Peak	0.000	
	Subtransmission On-Peak	0.000	
	Subtransmission Off-Peak	0.000	
591		0.000	
592		0.000	(C)

(1) Applicable April 1, 2011 through December 31, 2011.
(2) Not applicable to Customers served on Cost of Service.
(3) Applicable only to the Baseline and Scheduled Maintenance Energy.

SCHEDULE 128 (Continued)

Third Quarter – July 1st Balance of Year Adjustment Rate [(1)]

Schedule		¢ per kWh [(2)]	
38		0.000	
75	Secondary On-Peak	0.000 [(3)]	
	Secondary Off-Peak	0.000 [(3)]	
	Primary On-Peak	0.000 [(3)]	
	Primary Off-Peak	0.000 [(3)]	
	Subtransmission On-Peak	0.000 [(3)]	
	Subtransmission Off-Peak	0.000 [(3)]	
83		0.000	(C)
85	Secondary On-Peak	0.000 [(3)]	(N)
	Secondary Off-Peak	0.000 [(3)]	|
	Primary On-Peak	0.000 [(3)]	
	Primary Off-Peak	0.000 [(3)]	(N)
89	Secondary On-Peak	0.000	
	Secondary Off-Peak	0.000	
	Primary On-Peak	0.000	
	Primary Off-Peak	0.000	
	Subtransmission On-Peak	0.000	
	Subtransmission Off-Peak	0.000	
91		0.000	
538		0.000	
575	Secondary On-Peak	0.000 [(3)]	
	Secondary Off-Peak	0.000 [(3)]	
	Primary On-Peak	0.000 [(3)]	
	Primary Off-Peak	0.000 [(3)]	
	Subtransmission On-Peak	0.000 [(3)]	
	Subtransmission Off-Peak	0.000 [(3)]	(C)
583		0.000	(N)
585	Secondary On-Peak	0.000 [(3)]	
	Secondary Off-Peak	0.000 [(3)]	|
	Primary On-Peak	0.000 [(3)]	(N)
	Primary Off-Peak	0.000 [(3)]	
589	Secondary On-Peak	0.000	
	Secondary Off-Peak	0.000	
	Primary On-Peak	0.000	
	Primary Off-Peak	0.000	
	Subtransmission On-Peak	0.000	
	Subtransmission Off-Peak	0.000	
591		0.000	
592		0.000	

(C)

(1) Applicable July 1, 2011 through December 31, 2011.
(2) Not applicable to Customers served on Cost of Service.
(3) Applicable only to the Baseline and Scheduled Maintenance Energy.

SCHEDULE 128 (Concluded)

Fourth Quarter – October 1st Balance of Year Adjustment Rate [(1)]

Schedule		¢ per kWh [(2)]	
38		0.000	
75	Secondary On-Peak	0.000 [(3)]	
	Secondary Off-Peak	0.000 [(3)]	
	Primary On-Peak	0.000 [(3)]	
	Primary Off-Peak	0.000 [(3)]	
	Subtransmission On-Peak	0.000 [(3)]	
	Subtransmission Off-Peak	0.000 [(3)]	
83	Secondary	0.000	(C)
85	Secondary On-Peak	0.000 [(3)]	(N)
	Secondary Off-Peak	0.000 [(3)]	
	Primary On-Peak	0.000 [(3)]	
	Primary Off-Peak	0.000 [(3)]	(N)
89	Secondary On-Peak	0.000	
	Secondary Off-Peak	0.000	
	Primary On-Peak	0.000	
	Primary Off-Peak	0.000	
	Subtransmission On-Peak	0.000	
	Subtransmission Off-Peak	0.000	
91		0.000	
538		0.000	
575	Secondary On-Peak	0.000 [(3)]	
	Secondary Off-Peak	0.000 [(3)]	
	Primary On-Peak	0.000 [(3)]	
	Primary Off-Peak	0.000 [(3)]	
	Subtransmission On-Peak	0.000 [(3)]	
	Subtransmission Off-Peak	0.000 [(3)]	
583		0.000	(C)
585	Secondary On-Peak	0.000 [(3)]	(N)
	Secondary Off-Peak	0.000 [(3)]	
	Primary On-Peak	0.000 [(3)]	
	Primary Off-Peak	0.000 [(3)]	(N)
589	Secondary On-Peak	0.000	
	Secondary Off-Peak	0.000	
	Primary On-Peak	0.000	
	Primary Off-Peak	0.000	
	Subtransmission On-Peak	0.000	
	Subtransmission Off-Peak	0.000	
591		0.000	
592		0.000	

(1) Applicable October 1, 2011 through December 31, 2011. (C)
(2) Not applicable to Customers served on Cost of Service.
(3) Applicable only to the Baseline and Scheduled Maintenance Energy.

SCHEDULE 129
LONG-TERM TRANSITION COST ADJUSTMENT

AVAILABLE

In all territory served by the Company.

APPLICABLE

Applicable to Large Nonresidential Customers that have selected service under Schedule 485 and 489. **(C)**

TRANSITION COST ADJUSTMENT

Minimum Five Year Opt-Out

For Enrollment Period A (2002); No Longer Applicable **(C)**

0.000 ¢ per kWh after December 31, 2007

For Enrollment Period B (2003); No Longer Applicable **(C)** **(D)**

0.000 ¢ per kWh after December 31, 2008

For Enrollment Period C (2004); No Longer Applicable **(C)** **(D)**

For Enrollment Period D (2005); No Longer Applicable **(C)** **(D)**

SCHEDULE 129 (Continued)

TRANSITION COST ADJUSTMENT (Continued)
Three Year Opt-Out

This option was not available during Enrollment Periods A and B.

For Enrollment Period C (2004): No longer applicable

For Enrollment Period D (2005), No Longer Applicable **(C)**
(D)

For Enrollment Period E (2006); No Longer Applicable **(C)**

For Enrollment Period F (2007); No Longer Applicable **(C)**

For Enrollment Period G (2008), the Transition Cost Adjustment will be:

(1.043) ¢ per kWh	January 1, 2009 through December 31, 2009
(0.994) ¢ per kWh	January 1, 2010 through December 31, 2010
(0.720) ¢ per kWh	January 1, 2011 through December 31, 2011

For Enrollment Period H (2009), the Transition Cost Adjustment will be:

0.673 ¢ per kWh	January 1, 2010 through December 31, 2010
0.415 ¢ per kWh	January 1, 2011 through December 31, 2011
0.473 ¢ per kWh	January 1, 2012 through December 31, 2012

SCHEDULE 129 (Concluded)

SPECIAL CONDITIONS

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

2. Annually, changes in fixed generation revenues resulting from either return to or departure from Cost of Service pricing by Schedule 485 and 489 customers relative to the Company's most recent general rate case will be incorporated into the System Usage Charges of the Large Nonresidential Rate Schedules 75, 76R, 85, 89, 485, 489, 575, 576R, 585, and 589. Such adjustment to the System Usage or Distribution Charges will be made at the time the Company files final rates for Schedule 125, and will be effective on January 1st of the following calendar year. The adjustment to the System Usage Charge resulting from changes in fixed generation revenues shall not result in a rate increase or decrease to Schedules 85, and 89 of more than 2 percent. For purposes of calculating the percent change in rates, Schedule 125 prices with and without the increased/decreased Schedules 485 and 489 participating load will be determined. **(C)** **(C)** **(C)** **(C)**

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

Schedule		¢ per kWh	
			(D)
85	Secondary	2.279	**(N)**
	Primary	2.204	**(N)**
89	Secondary	2.184	**(I)**
	Primary	2.092	|
	Subtransmission	2.056	**(I)**

TERM

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

SCHEDULE 133
COLSTRIP TAX and ROYALTY PAYMENT ADJUSTMENT

PURPOSE

To recover from Customers taxes and royalty payments retroactively assessed by the U.S. Department of Interior and the Montana Department of Revenue.

APPLICABLE

To all bills for electric service calculated under all rate schedules listed below.

ADJUSTMENT RATE

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

Schedule	Adjustment Rate		
7	0.011	¢ per kWh	
12	0.011	¢ per kWh	(N)
15	0.011	¢ per kWh	
32	0.011	¢ per kWh	
38	0.011	¢ per kWh	
47	0.011	¢ per kWh	
49	0.011	¢ per kWh	
75			
Secondary	0.011	¢ per kWh	
Primary	0.011	¢ per kWh	
Subtransmission	0.011	¢ per kWh	
76R			
Secondary	0.011	¢ per kWh	
Primary	0.011	¢ per kWh	
Subtransmission	0.011	¢ per kWh	
83	0.011	¢ per kWh	(C)
85		¢ per kWh	(N)
Secondary	0.011	¢ per kWh	
Primary	0.011	¢ per kWh	(N)

SCHEDULE 133 (Continued)

ADJUSTMENT RATES (Continued)

Schedule	Adjustment Rate		
87			(M)
Secondary	0.011	¢ per kWh	
Primary	0.011	¢ per kWh	
Subtransmission	0.011	¢ per kWh	(M)
89			
Secondary	0.011	¢ per kWh	
Primary	0.011	¢ per kWh	
Subtransmission	0.011	¢ per kWh	
91	0.011	¢ per kWh	
92	0.011	¢ per kWh	
93	0.011	¢ per kWh	
94	0.011	¢ per kWh	(C)
485			
Secondary	0.011	¢ per kWh	
Primary	0.011	¢ per kWh	
489			
Secondary	0.011	¢ per kWh	
Primary	0.011	¢ per kWh	
Subtransmission	0.011	¢ per kWh	
515	0.011	¢ per kWh	
532	0.011	¢ per kWh	
538	0.011	¢ per kWh	
549	0.011	¢ per kWh	
575			
Secondary	0.011	¢ per kWh	
Primary	0.011	¢ per kWh	
Subtransmission	0.011	¢ per kWh	

SCHEDULE 133 (Concluded)

ADJUSTMENT RATES (Continued)

Schedule	Adjustment Rate		
576R			(M)
Secondary	0.011	¢ per kWh	
Primary	0.011	¢ per kWh	
Subtransmission	0.011	¢ per kWh	
583	0.011	¢ per kWh	(M)(C)
585			(N)
Secondary	0.011	¢ per kWh	
Primary	0.011	¢ per kWh	(N)
589			
Secondary	0.011	¢ per kWh	
Primary	0.011	¢ per kWh	
Subtransmission	0.011	¢ per kWh	
591	0.011	¢ per kWh	
592	0.011	¢ per kWh	
594	0.011	¢ per kWh	

BALANCING ACCOUNT

The Company will establish a Balancing Account to record the difference between amounts collected under this schedule and amounts authorized to be recovered. This Balancing Account will accrue interest at the Commission-authorized rate for deferred accounts. The disposition of any over or under-recovery amount will be subject to Commission approval.

TERM

This Schedule will terminate upon full collection of the taxes and royalty payments.

SCHEDULE 141
PENSION ADJUSTMENT MECHANISM

PURPOSE

This schedule recovers or refunds to Customers incremental amounts beyond those in base rates associated with the Company's expense and financing costs of incremental cash contributions related to the Company's employee pension plan funding obligations in compliance with the requirements of the Pension Protection Act of 2006 and FAS 87. This schedule is an "automatic adjustment clause" as defined by ORS 757.210.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all bills for Electricity Service.

ADJUSTMENT RATE

The Adjustment Rate, unless otherwise approved by the Commission, will be effective on January 1st of the applicable calendar year:

Schedule	Adjustment Rate
7	0.000 ¢ per kWh
12	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
76R	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh

SCHEDULE 141 (Continued)

ADJUSTMENT RATE (Continued)

Schedule	Adjustment Rate
83	0.000 ¢ per kWh
85	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
87	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
89	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
91	0.000 ¢ per kWh
92	0.000 ¢ per kWh
93	0.000 ¢ per kWh
94	0.000 ¢ per kWh
485	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
489	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
515	0.000 ¢ per kWh
532	0.000 ¢ per kWh
538	0.000 ¢ per kWh
549	0.000 ¢ per kWh

SCHEDULE 141 (Continued)

ADJUSTMENT RATE (Continued)

Schedule	Adjustment Rate
575	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
576R	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
583	0.000 ¢ per kWh
585	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
589	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
591	0.000 ¢ per kWh
592	0.000 ¢ per kWh
594	0.000 ¢ per kWh

ADJUSTMENT AMOUNT

The adjustment amount is the sum of applicable pension expense, Financing Cost, and the difference between actual and forecast pension expense from the prior period; adjusted by a revenue sensitive cost factor of 1.0352 to account for uncollectibles, franchise fees, and other revenue sensitive costs. For 2011, pension expense and Financing Cost are included in the Company's base rates and the adjustment amount is zero. The Financing Basis becomes part of base rates with each subsequent General Rate Case (GRC).

SCHEDULE 141 (Concluded)

ADJUSTMENT AMOUNT (Continued)

Financing Cost

Financing Cost equal the Financing Basis times the Rate.

Financing Basis

For 2012 and each year thereafter, the Financing Basis is the sum of: (A) the difference between cumulative actual cash contributions and cumulative actual pension expense since the last approved GRC minus the difference between forecast cash contributions and forecast pension expense as included in the last approved GRC, and (B) the difference between forecast cash contributions and forecast pension expense for the effective year.

Rate

The Rate is the Company's cost of capital grossed up for taxes.

TIME AND MANNER OF FILING

For each calendar year the Company will file no later than October 1, the following:

1. Revised rates under this schedule and a transmittal letter that summarizes the basis for the requested rate with an effective date of the following January 1st.

2. Work papers that support the calculation of the Adjustment Amount including: actual and forecast pension expense, cash contributions, Financing Basis, and forecast Financing Cost.

The Company will file the updated rates that are in compliance with the Commission's findings in the proceeding reviewing the October filing.

**SCHEDULE 145
BOARDMAN POWER PLANT
OPERATING LIFE ADJUSTMENT**

PURPOSE

This schedule establishes the mechanism to implement in rates the revenue requirement effect of a Commission-authorized change in the Boardman Power Plant's currently assumed end of life year of 2040. This schedule is implemented as an "automatic adjustment clause" as defined in ORS 757.210.

APPLICABLE

To all bills for Electricity Service except Schedules 9, 76R, 485, 489 and 576R.

ADJUSTMENT RATES

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

Schedule	Adjustment Rate
7	0.000 ¢ per kWh
12	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 145 (Continued)

ADJUSTMENT RATE (Continued)

Schedule	Adjustment Rate
87	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
89	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
91	0.000 ¢ per kWh
92	0.000 ¢ per kWh
93	0.000 ¢ per kWh
94	0.000 ¢ per kWh
515	0.000 ¢ per kWh
532	0.000 ¢ per kWh
538	0.000 ¢ per kWh
549	0.000 ¢ per kWh
575	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
583	0.000 ¢ per kWh
585	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh

SCHEDULE 145 (Concluded)

ADJUSTMENT RATE (Continued)

Schedule	Adjustment Rate
589	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
591	0.000 ¢ per kWh
592	0.000 ¢ per kWh
594	0.000 ¢ per kWh

DETERMINATION OF ADJUSTMENT AMOUNT

Any revision to this schedule's Adjustment Rates requires Commission authorization (by order, approval of a filing, acknowledgement of an Integrated Resource Plan's Action Plan or approval of a depreciation study) to revise for rate setting and accounting purposes, the end of life assumption of 2040 for the Boardman Power Plant. The revised Adjustment Rates will be set to recover an Adjustment Amount reflecting the change in depreciation revenue requirements.

The Adjustment Amount is the difference between the Boardman Power Plant depreciation/amortization revenue requirement for the year 2011 as determined in UE ___ that reflects a plant end of life date of 2040, and the same depreciation/amortization revenue requirement determination using a plant end of life assumption as ordered by the Commission. The depreciation/amortization revenue requirement change computation will use the Commission-authorized tax rates, revenue sensitive cost rates, rate of return and return on equity rates. Only changes to depreciation expense, amortization expense and related Schedule M and rate base adjustments as of the date of the filing revisions to this rate schedule are included in the depreciation/amortization revenue requirements.

The Adjustment Rates will be updated annually to reflect the subsequent year's change in the Boardman Power Plant deprecation revenue requirement, if the Company has not incorporated the revised depreciable life into base rates in a general rate case or other proceeding.

The reference docket numbers and dates in this schedule will be revised as necessary to a subsequent docket if no change to the Boardman depreciable life occurs prior to a subsequent general rate case order.

TERM

This schedule will terminate at the date that base rates include the revised end of life assumption or when all remaining investment in the Boardman Power Plant has been recovered.

SCHEDULE 300 (Continued)

LINE EXTENSIONS (Rule I)

Line Extension Allowance (Section 1)

Residential Service	$1,514.00 / dwelling unit	
Small Nonresidential Service (Schedules 15, 32 & 47)	$ 0.1129 /estimated annual kWh	
Large Nonresidential Service Secondary Voltage Service (Schedules 38, 49, 83, 85, 89 & 91)	$ 0.0524 /estimated annual kWh	**(C)**
Large Nonresidential Primary voltage service (Schedules 38, 49, 85 & 89)	$ 0.0295 /estimated annual kWh	**(C)**

Trenching or Boring (Section 3)

Trenching and backfilling associated with Service Installation except where General Rules and Regulations require actual cost.

In Residential Subdivisions:

Short-side service connection up to 30 feet	$ 100.00
Otherwise:	
First 75 feet or less	$ 219.00
Greater than 75 feet	$ 3.80 /foot

Mainline trenching, boring and backfilling — Estimated Actual Cost

Lighting Underground Service Areas[(1)]

Installation of conduit on a wood pole for lighting purposes — $ 75.00 per pole

Additional Services (Section 3)
(applies solely to Residential Subdivisions in Underground Service Areas)

Service Guarantee	$ 100.00
Wasted Trip Charge	$ 100.00
Service Locate Charge	$ 30.00
Long-Side Service Connection	$ 120.00

(1) Applies only to 1-inch conduit without brackets.

SCHEDULE 300 (Concluded)

SERVICE OF LIMITED DURATION (Rule L)

Standard Temporary Service

Service Connection Required:

No permanent Customer obtained	$530.00	**(I)**
Permanent Customer obtained		
Overhead Service	$355.00	**(N)**
Underground Service	$300.00	**(N)**
Existing service	$140.00	**(I)**

Enhanced Temporary Service

Fixed fee for 12-month period	$275.00	**(I)**

Temporary Area Lights	$400.00 (first luminaire)
	$345.00 (each additional luminaire)
	$450.00 (first pole)
	$400.00 (each additional pole)

SCHEDULE 485
LARGE NONRESIDENTIAL
COST OF SERVICE OPT-OUT
(201 - 1,000 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

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

ENROLLMENT PERIODS

Minimum Five-Year Option

Enrollment Period A: No longer Applicable.

Enrollment Period B: Applicable to any Customer who enrolled between September 1, 2003 and September 30, 2003 with a minimum service period from January 1, 2004 through December 31, 2008.

Enrollment Period C: Applicable to any Customer who enrolled between September 1, 2004 and September 30, 2004, with a minimum service period from January 1, 2005 through December 31, 2009.

Enrollment Period D: Applicable to any customer who enrolled between September 1, 2005 and September 30, 2005, with a minimum service period from January 1, 2006 through December 31, 2010.

Enrollment Period E: Applicable to any customer who enrolled between September 1, 2006 and September 30, 2006, with a minimum service period from January 1, 2007 through December 31, 2011.

Enrollment Period F: Applicable to any customer who enrolled between September 1, 2007 and September 30, 2007, with a minimum service period from January 1, 2008 through December 31, 2012.

Enrollment Period G: Applicable to any customer who enrolled between September 1, 2008 and September 30, 2008, with a minimum service period from January 1, 2009 through December 31, 2013.

SCHEDULE 485 (Continued)

ENROLLMENT PERIODS (Continued)
Minimum Five-Year Option (Continued)

Enrollment Period H: Applicable to any customer who enrolled between September 1, 2009 and September 30, 2009, with a minimum service period from January 1, 2010 through December 31, 2014.

Fixed Three-Year Option

This option was not available during Enrollment Periods A and B.

Enrollment Period C: No longer Applicable.

Enrollment Period D: Applicable to any Customer who enrolled between September 1, 2005 and September 30, 2005, with a service period from January 1, 2006 through December 31, 2008.

Enrollment Period E: Applicable to any Customer who enrolled between September 1, 2006 and September 30, 2006, with a service period from January 1, 2007 through December 31, 2009.

Enrollment Period F: Applicable to any Customer who enrolled between September 1, 2007 and September 30, 2007, with a service period from January 1, 2008 through December 31, 2010.

Enrollment Period G: Applicable to any customer who enrolled between September 1, 2008 and September 30, 2008, with a minimum service period from January 1, 2009 through December 31, 2011.

Enrollment Period H: Applicable to any customer who enrolled between September 1, 2009 and September 30, 2009, with a minimum service period from January 1, 2010 through December 31, 2012.

CHANGE IN APPLICABILITY

If a Customer's usage changes such that they no longer qualify as a Large Nonresidential Customer, they will have their service terminated under this schedule and will move to an otherwise applicable schedule.

SCHEDULE 485 (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
Basic Charge	$400.00	$360.00
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 200 kW	$2.04	$1.97
Over 200 kW	$2.04	$1.97
per kW of monthly On-Peak Demand	$1.95	$1.88
System Usage Charge		
per kWh	0.400 ¢	0.386 ¢

* See Schedule 100 for applicable adjustments.

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

MARKET BASED PRICING OPTION

Energy Supply

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

Direct Access Service

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

SCHEDULE 485 (Continued)

MARKET BASED PRICING OPTION (Continued)

Company Supplied Energy

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

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

Wheeling Charge

The Wheeling Charge will be $1.519 per kW of monthly Demand.

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 Facility Capacity and Demand (in kW) will be 200 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	1.0484
Secondary Delivery Voltage	1.0826

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 must give the Company not less than two years notice to terminate service under this schedule. Such notice 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 485 (Concluded)

SPECIAL CONDITIONS (Continued)

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.

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.

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

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.

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.

9. Customers selecting service under this schedule will be limited to a Company/ESS Split Bill.

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 two 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 489
LARGE NONRESIDENTIAL
COST-OF-SERVICE OPT-OUT
(>1000 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

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

ENROLLMENT PERIODS

<u>Minimum Five-Year Option</u>

Enrollment Period A: No longer Applicable.

Enrollment Period B: Applicable to any Customer who enrolled between September 1, 2003 and September 30, 2003 with a minimum service period from January 1, 2004 through December 31, 2008.

Enrollment Period C: Applicable to any Customer who enrolled between September 1, 2004 and September 30, 2004, with a minimum service period from January 1, 2005 through December 31, 2009.

Enrollment Period D: Applicable to any customer who enrolled between September 1, 2005 and September 30, 2005, with a minimum service period from January 1, 2006 through December 31, 2010.

Enrollment Period E: Applicable to any customer who enrolled between September 1, 2006 and September 30, 2006, with a minimum service period from January 1, 2007 through December 31, 2011.

Enrollment Period F: Applicable to any customer who enrolled between September 1, 2007 and September 30, 2007, with a minimum service period from January 1, 2008 through December 31, 2012.

Enrollment Period G: Applicable to any customer who enrolled between September 1, 2008 and September 30, 2008, with a minimum service period from January 1, 2009 through December 31, 2013.

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	$1,310.00	$1,040.00	$2,020.00	(I)
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.77	$1.73	$1.73	(R)(I)(C)
Over 4,000 kW	$0.38	$0.34	$0.34	(R) (C)
per kW of monthly On-Peak Demand	$2.05	$1.98	$0.91	(I)(R)
System Usage Charge				
per kWh	0.427 ¢	0.403 ¢	0.389 ¢	(I)

* See Schedule 100 for applicable adjustments.

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

MARKET BASED PRICING OPTION

Energy Supply

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

Direct Access Service

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

SCHEDULE 489 (Continued)

MARKET BASED PRICING OPTION (Continued)

Company Supplied Energy

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

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

Wheeling Charge

The Wheeling Charge will be $1.519 per kW of monthly Demand. **(R)**

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. **(C)**

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	1.0337	
Primary Delivery Voltage	1.0484	**(R)**
Secondary Delivery Voltage	1.0826	**(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 must give the Company not less than two years notice to terminate service under this schedule. Such notice 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 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	$ 8.10 [2]	(I)
	400	21,000	147	11.13 [2]	
	1,000	55,000	374	20.27 [2]	
HPS	70	6,300	30	6.56 [2]	
	100	9,500	43	7.08	
	150	16,000	62	7.81	
	200	22,000	79	8.88	
	250	29,000	102	9.75	
	310	37,000	124	11.30 [2]	
	400	50,000	163	12.03	(I)

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

SCHEDULE 515 (Continued)

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

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate[1] Per Luminaire	
Flood , HPS	100	9,500	43	$ 7.47 [2]	(I)
	200	22,000	79	8.97 [2]	
	250	29,000	102	10.10	
	400	50,000	163	12.35	
Shoebox, HPS (bronze color, flat lens, or drop lens, multi-volt)	70	6,300	30	7.37	
	100	9,500	43	8.05	
	150	16,500	62	9.03	
Special Acorn Type, HPS	100	9,500	43	10.95	
HADCO Victorian, HPS	150	16,500	62	11.36	
	200	22,000	79	12.11	
	250	29,000	102	13.04	
Early American Post-Top, HPS, Black	100	9,500	43	8.04	
Special Types					
Cobrahead, Metal Halide	175	12,000	71	8.39	
Flood, Metal Halide	400	40,000	156	12.07	
Flood, HPS	750	105,000	285	19.25	
HADCO Independence, HPS	100	9,500	43	10.30	
	150	16,000	62	11.01	
HADCO Capitol Acorn, HPS	100	9,500	43	14.62	
	150	16,000	62	15.33	
	200	22,000	79	15.95	
	250	29,000	102	16.97	
HADCO Techtra, HPS	100	9,500	43	17.97	
	150	16,000	62	18.68	
	250	29,000	102	26.78	
KIM Archetype, HPS	250	29,000	102	14.38	
	400	50,000	163	16.42	
Holophane Mongoose, HPS	150	16,000	62	10.04	
	250	29,000	102	11.59	
	400	40,000	163	13.86	(I)

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

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	$12.00	**(R)**
Three Phase	$16.00	**(R)**
Distribution Charge		
First 5,000 kWh	3.541 ¢ per kWh	**(I)**
Over 5,000 kWh	0.817 ¢ 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, 2006.

MONTHLY RATE

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

Basic Charge			
Single Phase Service	$20.00		
Three Phase Service	$25.00		
Distribution Charge	5.372	¢ 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**	$30.00	
Winter Months**	No Charge	
Distribution Charge		
First 50 kWh per kW of Demand	3.276 ¢ per kWh	(I)
Over 50 kWh per kW of Demand	1.276 ¢ 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. **(C)**

CHARACTER OF SERVICE

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

MONTHLY RATE

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

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge				
Three Phase Service	$1,310.00	$1,040.00	$2,020.00	**(I)**
Distribution Charge				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.77	$1.73	$1.73	**(R)(I)(C)**
Over 4,000 kW	$0.38	$0.34	$0.34	**(R) (C)**
per kW of monthly On-Peak Demand**	$2.05	$1.98	$0.91	**(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	0.427 ¢	0.403 ¢	0.389 ¢	**(I)**

* 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	
				(C)
Daily Economic Replacement Power (ERP) Demand Charge				
per kW of Daily ERP Demand during On-Peak hours per day**	$0.080	$0.077	$0.035	(I)(R)
System Usage Charge				
per kWh of ERP	0.427 ¢	0.403 ¢	0.389 ¢	(I)
Transaction Fee				
per Energy Needs Forecast (ENF) submission or revision	$50.00	$50.00	$50.00	(C)

* 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) **(C)**

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has not exceeded 200 kW more than once in the proceeding 13 months and who have chosen to receive Electricity from an Electricity Service Supplier (ESS). **(C)**

CHARACTER OF SERVICE

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

MONTHLY RATE

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

(D)

Basic Charge		
Single Phase Service	$20.00	(I)
Three Phase Service	$30.00	
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 30 kW	$3.00	(I)
Over 30 kW	$2.50	(I)
per kW of monthly Demand	$1.83	(R)
System Usage Charge		
per kWh	0.380 ¢	(I)

(D)

* 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 583 (Continued)

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.

FACILITY CAPACITY

The Facility Capacity shall 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. **(C)**

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 include those summarized in Schedule 100.

NOVEMBER ELECTION WINDOW

Enrollment for 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 Enrollment Windows 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 585
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE
(201 – 1,000 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has exceeded 200 kW but not exceeded 1,000 kW more than once in the proceeding 13 months and 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 at the applicable Delivery Voltage per Point of Delivery (POD)*:

	Delivery Voltage	
	Secondary	Primary
Basic Charge	$400.00	$360.00
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 200 kW	$2.04	$1.97
Over 200 kW	$2.04	$1.97
per kW of monthly On-Peak Demand	$1.95	$1.88
System Usage Charge		
per kWh	0.400 ¢	0.386 ¢

* 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 (Continued)

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.

FACILITY CAPACITY

The Facility Capacity shall 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.

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 include those summarized in Schedule 100.

NOVEMBER ELECTION WINDOW

Enrollment for 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 Enrollment Windows 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 585 (Concluded)

SPECIAL CONDITIONS

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

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.

TERM

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

SCHEDULE 589
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE
(>1000 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has exceeded 1,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 1,000 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	$1,310.00	$1,040.00	$2,020.00	**(I)**
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.77	$1.73	$1.73	**(R)(I)(C)**
Over 4,000 kW	$0.38	$0.34	$0.34	**(R) (C)**
per kW of monthly on-peak Demand	$2.05	$1.98	$0.91	**(I) (R)**
System Usage Charge				
per kWh	0.427 ¢	0.403 ¢	0.389 ¢	**(I)**

* See Schedule 100 for applicable adjustments.

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

SCHEDULE 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 luminaire based on the Monthly kWhs applicable to each installed luminaire.

Distribution Charge	3.654 ¢ per kWh	**(I)**
Energy Charge	Provided by Energy Service Supplier	

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Installation Labor Rates [(1)]	Straight Time	Overtime
	$117.00 per hour	$165.00 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.

SCHEDULE 591 (Continued)

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 **	100	9,500	43	*	$4.13	$1.57	(I)
	150	16,000	62	*	4.84	2.27	
	200	22,000	79	*	5.50	2.89	
	250	29,000	102	*	6.34	3.73	
	400	50,000	163	*	8.58	5.96	
Cobrahead	100	9,500	43	$6.80	4.32	1.57	
	150	16,000	62	7.52	5.03	2.27	
	200	22,000	79	8.55	5.69	2.89	
	250	29,000	102	9.42	6.52	3.73	
	400	50,000	163	11.69	8.79	5.96	
Flood	250	29,000	102	9.73	6.59	3.73	
	400	50,000	163	11.98	8.84	5.96	
Early American Post-Top	100	9,500	43	7.28	4.40	1.57	
Shoebox (Bronze color, flat	70	6,300	30	6.94	3.92	1.10	
Lens, or drop lens, multi-volt)	100	9,500	43	7.68	4.47	1.57	
	150	16,000	62	8.63	5.18	2.27	(I)

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

RATES FOR STANDARD POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B
Fiberglass, Black	20	$4.10	$0.14
Fiberglass, Bronze	30	5.47	0.18
Fiberglass, Gray	30	5.49	0.18
Wood, Standard	30 to 35	4.71	0.15
Wood, Standard	40 to 55	5.91	0.20

SCHEDULE 591 (Continued)

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	$10.31	$4.80	$1.57	(I)
HADCO Independence, HPS	100	9,500	43	9.73	4.81	1.57	
	150	16,000	62	10.44	5.52	2.27	
HADCO Capitol Acorn, HPS	100	9,500	43	13.62	4.91	1.57	
	150	16,000	62	14.33	5.62	2.27	
	200	22,000	79	14.95	6.24	2.89	
	250	29,000	102	15.79	7.08	3.73	
Special Architectural Types							
HADCO Victorian, HPS	150	16,000	62	10.75	5.50	2.27	
	200	22,000	79	11.50	6.21	2.89	
	250	29,000	102	12.42	7.05	3.73	
HADCO Techtra, HPS	100	9,500	43	16.70	5.78	1.57	
	150	16,000	62	17.41	6.49	2.27	
	250	29,000	102	24.89	8.55	3.73	
KIM Archetype, HPS	250	29,000	102	*	7.06	3.73	
	400	50,000	163	*	9.28	5.96	
HADCO Westbrooke, HPS	70	6,300	30	14.10	4.50	1.10	
	100	9,500	43	14.53	4.96	1.57	
	150	16,000	62	15.24	5.67	2.27	
	200	22,000	79	16.00	6.29	2.89	
	250	29,000	102	16.84	7.13	3.73	
Special Types							
Cobrahead, Metal Halide	175	12,000	71	8.09	5.54	2.59	
Flood, Metal Halide	400	40,000	156	11.72	8.70	5.70	
Flood, HPS	750	105,000	285	18.74	14.33	10.41	
Holophane Mongoose, HPS	150	16,000	62	9.54	5.27	2.27	
	250	29,000	102	11.09	6.74	3.73	
	400	50,000	163	13.36	8.99	5.96	(I)

* Not offered.

SCHEDULE 591 (Continued)

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	*	*	$1.43	(I)
	175	7,000	66	$7.79	$5.12	2.41	
	250	10,000	94	9.72	6.35	3.43	
	400	21,000	147	10.82	8.16	5.37	
	1,000	55,000	374	19.90	16.75	13.67	
Special Box Similar to GE "Space-Glo"							
HPS	70	6,300	30	9.81	3.93	1.10	
Mercury Vapor	175	7,000	66	11.26	5.16	2.41	
Special box, Anodized Aluminum							
Similar to GardCo Hub							
HPS	Twin 70	6,300	60	*	*	2.19	
	70	6,300	30	*	*	1.10	
	100	9,500	43	10.07	4.72	1.57	
	150	16,000	62	*	5.43	2.27	
	250	29,000	102	*	*	3.73	
	400	50,000	163	*	*	5.96	
Metal Halide	250	20,500	99	*	6.98	3.62	
	400	40,000	156	*	9.44	5.70	
Cobrahead, Dual Wattage HPS							
70/100 Watt Ballast	100	9,500	43	*	4.30	1.57	
100/150 Watt Ballast	100	9,500	43	*	4.30	1.57	
100/150 Watt Ballast	150	16,000	62	*	5.01	2.27	
Special Architectural Types							(I)
KIM SBC Shoebox, HPS	150	16,000	62	*	5.92	2.27	

* 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	$9.58	$3.93	$1.10	(I)
Special GardCo Bronze Alloy							
HPS	70	5,000	30	*	*	1.10	
Mercury Vapor	175	7,000	66	*	*	2.41	
Special Acrylic Sphere							
Mercury Vapor	400	21,000	147	*	*	5.37	
Early American Post-Top, HPS							
Black	70	6,300	30	6.19	3.83	1.10	
Rectangle Type	200	22,000	79	*	*	2.89	
Incandescent	92	1,000	31	*	*	1.13	
	182	2,500	62	*	*	2.27	
Town and Country Post-Top							
Mercury Vapor	175	7,000	66	7.89	5.11	2.41	
Flood, HPS	70	6,300	30	6.79	3.90	1.10	
	100	9,500	43	7.15	4.34	1.57	
	200	22,000	79	8.87	5.73	2.89	
Cobrahead, HPS							
Non-Power Door	70	6,300	30	6.28	3.89	1.10	
Power Door	310	37,000	124	10.93	7.67	4.53	
Special Types Customer-Owned & Maintained							
Ornamental, HPS	100	9,500	43	*	*	1.57	
Twin ornamental, HPS	Twin 100	9,500	86	*	*	3.14	
Compact Fluorescent	28	N/A	12	*	*	0.44	(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	$5.83	*
Bronze Alloy GardCo	12	*	$0.24
Concrete, Ornamental	35 or less	9.48	0.32
Steel, Painted Regular **	25	9.48	0.32
Steel, Painted Regular **	30	10.26	0.34
Steel, Unpainted 6-foot Mast Arm **	30	*	0.34
Steel, Unpainted 6-foot Davit Arm **	30	*	0.35
Steel, Unpainted 8-foot Mast Arm **	35	*	0.38
Steel, Unpainted 8-foot Davit Arm **	35	*	0.38
Wood, Laminated without Mast Arm	20	5.30	0.14
Wood, Laminated Street Light Only	20	4.10	*
Wood, Curved Laminated	30	6.84	0.25
Wood, Painted Underground	35	4.71	0.20
Wood, Painted Street Light Only	35	4.71	*

* 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	$11.76	$3.22	$1.17	(I)
	165	12,000	60	14.47	4.32	2.19	
HADCO Techtra, QL	85	6,000	32	15.14	3.35	1.17	
	165	12,000	60	16.87	4.41	2.19	(I)

SCHEDULE 592
TRAFFIC SIGNALS
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

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

CHARACTER OF SERVICE

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

MONTHLY RATE

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

Distribution Charge	2.563 ¢ 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 594
COMMUNICATION DEVICES ELECTRICITY SERVICE RIDER
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments that have communication devices with energy requirements not exceeding 25 line watts per unit, that are installed on streetlights and, or traffic signals served under Schedules 91 and, or 92.

CHARACTER OF SERVICE

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

MONTHLY RATE*

The charge per Point of Delivery is:*

Distribution Charge	2.563 ¢ per kWh	**(I)**

* See Schedule 100 for applicable adjustments

The monthly kWh charge for service under this rider will be the number of units times estimated monthly usage determined using the following formula:

[((No. of Units x line watts per unit) x annual operating hours) / 1000] / 12

Where:
1) Annual operating hours are 8760
2) Line watts are based on the electrical data provided in the manufacturer's product specifications using the following criteria:

[(110 nominal volts x rated amps) x percentage of operational rating]

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:	6.20%	2.78%	1.31%	**(R)**

RULE G
DIRECT ACCESS SERVICE AND BILLING

1. Direct Access Service

All Customers, except Residential, may elect to receive Direct Access Service from an ESS under the terms of the parallel Direct Access schedule (500 series). Direct Access Service is also an option for eligible Nonresidential Customers served on Schedules 485 and 489. **(C)**

A. **Enrollment**

Direct Access Service is only available upon acceptance of an Enrollment DASR by the Company. Prerequisites and notification requirements are as contained in each service schedule and Rule K.

B. **Emergency Default Service**

The Company will provide Emergency Default Service under Schedule 81 when an ESS or the Customer informs the Company that the ESS is no longer providing service or when the Company becomes aware that the Customer is no longer receiving service from the ESS and the Company has not received the 10 business day notice required for Standard Service under the appropriate schedule.

2. Special Requirements for Direct Access Billings

A. **Generally**

A Customer purchasing Electricity from an ESS may choose from two billing options: the ESS bills for all services (ESS Consolidated Bill) or the Company and the ESS each bill for their respective services (Company/ESS Split Bill).

1) **Company/ESS Split Bill**

When the Customer is receiving a Company/ESS Split Bill, the Company may disconnect Electricity Service for nonpayment of Direct Access Service under the guidelines set forth in Rule H.

2) **ESS Consolidated Bill**

When the Customer receives an ESS Consolidated Bill, failure of the Customer to pay the ESS for Direct Access Service does not relieve the ESS of the responsibility to pay the Company for Direct Access Services and any other Company charges.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE

In the Matter of the Revised Tariff Schedules for Electric Service in Oregon filed by PORTLAND GENERAL ELECTRIC COMPANY	))))	**PRETRIAL BRIEF OF PORTLAND GENERAL ELECTRIC COMPANY**

I. INTRODUCTION

In this docket Portland General Electric Company ("PGE") requests to revise its tariff schedules pursuant to ORS 757.205 and ORS 757.220. This brief is submitted to meet the requirements of OAR 860-013-0075.

It has been two years since PGE's last rate case. The last two years have been unusual and difficult for many businesses and individuals in Oregon and across the country, PGE included. In PGE's case, the economic downturn has caused a significant decrease in retail loads from the levels previously expected. This has adversely impacted PGE's revenues without a commensurate reduction in the cost of providing services to customers.

PGE has taken a number of measures to reduce expenses and improve its efficiency, and has made this request for a rate adjustment only after much deliberation. Not all of the steps taken to reduce expenses can be sustained without adversely impacting service quality, system reliability, or the financial condition of the company to an extent that would be detrimental to customers and long-term costs. The latter is particularly important given the large amount of capital that PGE will need to raise in the near term to meet its service and regulatory requirements.

In previous dockets some parties have questioned the efficiency of PGE's operations. This filing includes testimony by PGE's Chief Financial Officer, Maria Pope, specifically addressing efficiency and cost effectiveness efforts of the company. Ms. Pope's testimony includes a report commissioned by PGE and prepared by the Pacific Economics Group ("Pacific Economics"). Pacific Economics performed a statistical, or econometric, benchmarking analysis of PGE's costs using a large sample of distribution and generation utilities. Pacific Economics provided a detailed report of their findings that is included as an exhibit to Ms. Pope's testimony. This analysis determined that PGE's O&M costs are slightly below average, but not statistically different from that of other utilities. The analysis further showed that with respect to two measures of reliability, SAIDI and SAIFI, PGE "is a significantly superior reliability performer."[1] Ms. Pope also addresses specific actions PGE management and employees have taken to decrease costs and increase efficiency throughout the company.

The drivers for PGE's request, and its impact on the present and future ability of PGE to provide the service customers expect and regulations demand, are discussed more thoroughly in the testimony provided by PGE President and Chief Executive Officer Jim Piro. Mr. Piro discusses the rigorous budgeting process undertaken by PGE, consistent with the company's obligation to meet our customers' expectations for service quality, reliability, regulatory compliance and safety. In addition, Mr. Piro directed that two major steps be taken to reduce this requested price increase. First, while the analysis of PGE's return on equity ("ROE") expert Mr. Zepp indicates that PGE should seek an 11% ROE, Mr. Piro directed that PGE's filing contain a request for an ROE of 10.5% in recognition of the current economic climate and the assumption that the PCAM changes and other proposals filed in the case are adopted. Second, Mr. Piro directed that this filing not request recovery of the cost of officer incentives and only half the cost of employee incentive programs. While these programs are a prudent and necessary part of retaining a competitive workforce, these costs are not included to mitigate the requested price increase. Together these actions eliminated about $23 million (or about 1.5%) from the requested increase in this case.

---

[1] As is addressed in testimony, PGE has also performed very well in measures of customer service and customer satisfaction.

PGE is making, and has made, very significant investments in its facilities in the past few years. Among these are the completion of three phases of the Biglow Canyon wind farm and Advanced Metering Infrastructure ("AMI"). There are very significant capital needs in the coming years for additional renewable generation, hydro relicensing obligations, investment in emission controls for the Boardman plant or in alternative generation, and peaker capacity. The proposed Cascade Crossing transmission project to support reliability and cost containment will also require sizeable capital investment. These will require significant capital on the part of PGE whether new plant is constructed by PGE or some resources are acquired through contract with third parties. As a result, PGE will be raising capital by issuing debt and equity at considerably increased levels. Sufficient cost coverage through rates is critical in order for PGE to obtain this capital at favorable terms, lowering long-term costs for customers.

II. SUMMARY OF THIS CASE

This case is based on a normalized future test period of calendar year 2011. 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, 2011.

In this general rate case PGE requests an overall price increase of 7.4% effective January 1, 2011. The increase in revenue over what would be expected under current prices is about $125 million. As set out in the testimony, about 4.25% is related to investments needed by PGE to fulfill its legal mandates and provide reliable service to customers. The largest part of this investment-related expense is the inclusion of Phase 3 of the Biglow Canyon wind generating project, which will be completed and begin service during 2010. The remainder of the request is due to increased operations and maintenance ("O&M") costs. These include expenses to maintain the level of service PGE customers expect, as well as costs due to regulatory requirements and external cost drivers including pension plan funding and health insurance cost increases. Net variable power costs are projected to partially mitigate these increases, with a decrease of about a 2%.

PGE requests an authorized ROE of 10.5%. The projected test year results show that, without a rate increase, PGE will earn an ROE of approximately 6%. That is significantly below PGE's currently authorized ROE, and below the level needed to maintain PGE's credit and attract capital. In addition, due to the operation of SB 408 we would expect a significant refund absent a rate increase that would further damage PGE's financial performance.

Taken together these cost increases require revised rates and schedules that meet our customers' needs for reasonable services and PGE's need for the opportunity to earn a return on invested capital that is commensurate with similar companies, allowing it to maintain its credit and attract capital on terms that will ultimately be beneficial to customers.

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

Net Variable Power Costs. Each year under Schedule 125, PGE's rates are adjusted to reflect projected net variable power costs ("NVPC") for the coming year, and transition charges or credits for those customers opting for an alternate electricity supplier are calculated. Schedule 125 requires PGE to file estimates of the adjustments on or before April 1. In addition to the NVPC forecast and Minimum Filing Requirements ("MFR's") 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 2010 open access window.

Income Taxes. This filing is a general rate proceeding or other general rate revision under OAR 860-022-0041. The order in this docket will reset the values used in the calculation of "taxes authorized to be collected in rates" as used in that rule.

Compliance with OAR 860-013-0075. Attached as Exhibit 1 is the information required by OAR 860-013-0075. That exhibit indicates that the impact of the requested rate change on residential customers is 8.8%. PGE's filing also includes a change in the rate design for residential customers that includes revised blocking or rate tiers. Under PGE's proposed rate design, the increase in base rates for an average residential customer using 900 kWh per month is 6.7% (including the impact of other adjustments such as the RPA Exchange Credit, the change is 7.0%).

III. TESTIMONY

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

EXHIBIT NO.	TITLE	WITNESSES
100	Policy	Jim Piro
200	Corporate Performance and Efficiency	Maria Pope
300	Revenue Requirements	Alex Tooman and Jay Tinker
400	Net Variable Power Costs	Mike Niman, Terri Peschka and Patrick Hager

500	Compensation	Arleen Barnett and Joyce Bell
600	Information Technology	Cam Henderson and Behzad Hosseini
700	Production O&M	Steve Quennoz and Arya Behbehani
800	Transmission and Distribution	Steve Hawke and Bill Nicholson
900	Customer Service	Steve Hawke
1000	Corporate Support	Maria Pope and Alex Tooman
1100	Cost of Capital	Patrick Hager and William Valach
1200	Return on Equity	Thomas M. Zepp
1300	PCAM	Steven Fetter
1400	Load Forecast	Ham Nguyen
1500	Pricing	Doug Kuns and Marc Cody

IV. SUMMARY OF TESTIMONY

Exhibit 100. Jim Piro presents the opening testimony. Mr. Piro describes PGE's business and regulatory environment, the changes PGE is experiencing, the significant factors contributing to the need for a rate increase, and actions taken by PGE to mitigate this rate request. Mr. Piro also identifies and briefly discusses a number of policy issues in this docket including recovery of pension expenses, storm damage expenses, proposed changes to the PCAM mechanism, the inclusion of collateral costs in NVPC, and a tariff to recognize the depreciation impact of decisions regarding the future operations of PGE's Boardman power plant. Mr. Piro further requests and recommends the continuation of the decoupling mechanism approved in PGE's last rate case, UE 197. Mr. Piro also introduces the other testimony in this docket.

Exhibit 200. Maria Pope addresses two subjects. First, she discusses PGE's efforts to promote efficiency and cost effective operations. Included in this discussion is the econometric benchmarking cost comparisons performed by Pacific Economics Group discussed above. Ms. Pope also addresses specific efficiency actions taken at PGE. Second, Ms. Pope presents PGE's proposal to modify the power cost adjustment mechanism ("PCAM"). Ms. Pope's testimony references a PGE study which demonstrates that PGE's PCAM structure is an outlier relative to others. As discussed in this testimony, PGE proposes that the PCAM deadband be narrowed, made symmetrical, and expressed in dollar terms rather than as a percentage of ROE. Elimination of the earnings test deadband is also proposed. Ms. Pope also refers to and introduces the testimony of Steven Fetter regarding power cost adjustment mechanisms. Mr. Fetter's testimony is summarized below.

Exhibit 300. Alex Tooman and Jay Tinker summarize the overall revenue requirement of $1,811 million. Messrs. Tooman and Tinker explain that PGE is using a 2011 test year, and compare the request with the Commission approved revenue requirement and 2008 actual results. Their testimony also presents PGE's recent and test-year capital expenditures and PGE's rate base. The average 2011 rate base is $3,244 million, a significant increase over 2009 test year rate base. PGE's unbundled revenue requirement is also presented.

In addition, Messrs. Tooman and Tinker address the types and amount of savings in the test year as a result of the installation of PGE's AMI system.

This testimony further contains PGE's request for several accounting Orders to accurately reflect costs in rates while tempering the volatility of rates:

- An Order to create a regulatory balancing account to track the differences between actual storm damage costs and the accrual or estimate included in ratemaking. PGE previously had insurance for such costs.

- An Order establishing a balancing account to track differences between PGE's estimated pension expense and actual pension expense as recorded on PGE's financial statements. If approved, this balancing account will be part of a proposed Automatic Adjustment Clause (AAC) tariff for pension-related costs also requested in this docket. Like many companies, PGE's pension costs are expected to be significantly different in the next few years than has been the case historically.
- An Order allowing the tracking and recording of the differences between projected and actual environmental mitigation and remediation expenses for specifically identified projects. Such costs are anticipated to vary significantly year-to-year, and this mechanism will properly capture this variance.
- An Order allowing PGE to accrue long-term debt costs on the study costs of self-build options for IRP or RFP purposes. The testimony addresses the reasons for this request and the proposed accounting.
- An Order that allows PGE to account for the costs of collateral requirements related to power and natural gas trades, and include the costs as a part of NVPC for ratemaking purposes.
- An Order that will allow PGE to spread the development O&M costs of PGE's Information Technology system replacement program ("2020 Vision") over the life of the project. This will significantly reduce the rate impact that would result if these costs were included in the years in which they occur.

Exhibit 400. Mike Niman, Terri Peschka and Patrick Hager present PGE's Net Variable Power Costs. The initial NVPC forecast for 2011 is $747.2 million. This is a decrease of about $1.63 per MWh, from the 2010 NVPC determined in PGE's recent Annual Update Tariff proceeding, Docket UE 208. As previously mentioned, this results in a projected rate decrease of about 2%. This testimony addresses certain updates and modeling changes to PGE's Monet power cost model proposed in this docket. These witnesses additionally address the reason and need for PGE's request regarding the inclusion of collateral deposits as a part of NVPC.

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 2010 open access window.

Exhibit 500. Arleen Barnett and Joyce Bell testify on compensation and human resource issues. They describe the significant changes that have occurred in this area since 2008. They explain PGE's practice of setting total compensation to the market median. Total compensation in the 2011 test year is approximately $278 million. Increased compensation costs are primarily driven by benefits, particularly health care costs. After adjusting for AMI, the annual increase in FTE's is less than 0.5% since 2008.

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

In addition, these witnesses address PGE's pension plan and expenses, and the changes that have been made in this area. They set out the funding requirements for the pension plan, and PGE's options in this area. They also provide testimony and support for PGE's requested

Pension Adjustment Mechanism.

Exhibit 600. Cam Henderson and Behzad Hosseini explain the costs associated with PGE's Information Technology ("IT") function. IT costs continue to become a larger portion of overall PGE costs in virtually all areas of the company, and these witnesses explain the costs and changes from 2008. These witnesses also describe and support two major IT projects: cyber security and the 2020 Vision program, PGE's IT system replacement program.

Finally, these witnesses support the request for an accounting Order to smooth the impact of development O&M over a more appropriate period than standard GAAP accounting would allow.

Exhibit 700. PGE's long-term power supply resources and associated costs are presented by Steve Quennoz and Arya Behbehani. They also provide information regarding relicensing of PGE's hydro facilities. Forecasted 2011 costs for power operations and plant-related O&M expenses are $118.6 million. These witnesses discuss the primary drivers of increased costs since 2008 including required maintenance at the Colstrip 3 and 4 plants, the addition of Biglow Canyon phases 2 and 3, increased maintenance expense at Coyote Springs, fly ash disposal costs at Boardman, increased labor expense at hydro facilities, increased IT allocations, and increased land use fees at hydro facilities. These witnesses also provide the capital expenditures for Biglow Canyon phase 3, and at PGE's thermal and hydro plants.

In addition, these witnesses provide testimony regarding PGE's Environmental Services, and the additional costs that PGE is incurring in this area. The testimony describes projects that are connected to generation facilities and the relicensing process. Further testimony is also provided regarding environmental cleanup costs through the test year and beyond. The testimony describes the specific projects that are included in PGE's proposed environmental remediation expense tracking mechanism, and the details of that proposed mechanism.

Additionally, this testimony addresses cost saving and efficiency measures taken in this area of the company.

Exhibit 800. Steve Hawke and Bill Nicholson testify regarding PGE's transmission and distribution ("T&D") system. They explain the operational and capital costs necessary to provide service and the changes in those costs since 2008. T&D operations and maintenance expenses are projected to be approximately $97 million in the 2011 test year. T&D capital expenditures are projected to be about $149 million in 2011. These witnesses support and provide the details of the request for a balancing account for major storm damage expenses that were previously covered largely by insurance. The testimony also specifically addresses three programs that account for most of the increase in distribution O&M expense: tree trimming, Facility Inspection and Treatment to the National Electric Safety Code (FITNES), and underground utility locating.

Exhibit 900. Mr. Hawke also addresses PGE's Customer Services functions and costs. The areas covered in the customer service testimony account for most interactions with retail customers. Customer service costs in the 2011 test year are about $71 million. The testimony explains PGE's approach to customer service, the feedback PGE receives from customers, and how PGE uses that feedback and other measurements to continue to meet the changing expectations of customers. Finally, the testimony discusses the major drivers of cost changes in this area: increasing IT costs, increasing uncollectible accounts, and decreasing meter reading expenses due to implementation of AMI.

Exhibit 1000. Maria Pope and Alex Tooman address PGE's administrative and general (A&G") expenses. Test year A&G expenses are approximately $126.2 million. This represents a 2.1% annual change from 2008 actual A&G expenses. The testimony addresses the main reasons for the increased costs including higher benefit costs, insurance premiums, research and development costs, higher Western Electricity Coordinating Council membership costs, increasing requirements for environmental services, and higher IT costs.

Exhibit 1100. Patrick Hager and William Valach present PGE's testimony on cost of capital and capital structure. On behalf of PGE, these witnesses request an 8.289% cost of capital for PGE. This includes an ROE of 10.5%[2] and long-term debt cost of 6.077%. The witnesses address the impact of the Commission's decision regarding return on equity on PGE's credit quality and the future cost of raising capital. They also discuss the impact of the current PCAM mechanism on PGE's financial situation, and the impact of the proposed changes to the PCAM. These witnesses discuss and provide further support for the continuation of the decoupling mechanism adopted in UE 197.

In addition, Messrs. Hager and Valach discuss the impact of collateral costs on PGE, and further support the proposal that such costs should be included in NVPC calculations in the Annual Update Tariff and PCAM.

These witnesses also address PGE's current and proposed test-year capital structure. As discussed, PGE plans to issue $300 million in common equity in 2011. In this docket PGE proposes the same capital structure for ratemaking as was used in UE 197, 50% equity and 50% debt. Finally, the witnesses address some of the specific risks PGE encounters that are relevant

[2] As discussed earlier, even though the analysis and testimony of Mr. Zepp in Exhibit 1200 regarding the appropriate ROE indicates an 11% return, at the direction of Mr. Piro the request in this case is based on an ROE of 10.5%.

to PGE's cost of capital and to the appropriate return on equity to be used in this docket.

Exhibit 1200. Thomas M. Zepp addresses PGE's equity costs. Mr. Zepp addresses the risks PGE faces compared to the cost of common equity that faces a typical electric utility. Mr. 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, Mr. Zepp concludes that PGE's required return on equity falls in a range of 10.9% to 12%, with a recommendation that PGE's authorized ROE be no less than 11%.

Exhibit 1300. Exhibit 1300 is testimony prepared by Steven Fetter. Mr. Fetter is a former Chair of the Michigan Public Service Commission, and following that was employed by the Fitch credit rating agency to analyze utility regulatory and legislative developments. Mr. Fetter has provided testimony before numerous state and federal agencies and legislative bodies. PGE asked Mr. Fetter to address the company's current PCAM structure from a regulatory perspective and its impact on PGE's credit ratings and cost of capital. This testimony addresses those issues and makes recommendations regarding the design of PCAM mechanisms.

Exhibit 1400. Ham Nguyen presents PGE's load forecast for 2011. He forecasts that total retail loads will remain essentially flat from 2009 levels on a weather-adjusted basis. PGE will update the load forecast during this case as more information becomes available.

Exhibit 1500. Doug Kuns and Marc Cody testify on pricing. They specifically address the changes to marginal cost estimation, ratespread and rate design that PGE proposes. The proposals are the same as have been discussed previously in docket UM 1415.

The proposed base rate change, including power cost related changes, is 7.4% overall.

The increase by class varies: 8.8% overall for residential customers, 8.3% for small non-residential customers, 5.6% for large non-residential customers, and 2% for lighting and signal customers. However, as a result of the proposed revised blocking for residential Schedule 7 customers, an average residential customer using 900 kWh per month will see a base rate increase of 6.7% under this request. Messrs. Kuns and Cody also present and discuss Schedule 145, the Boardman Power Plant Operating Life schedule, and Schedule 141, the Pension Adjustment Mechanism. These witnesses also describe certain changes proposed in Schedules 123, 125, 126 and 300.

V. 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.

Dated: this 16th day of February, 2010.

Respectfully submitted,

DOUGLAS C. TINGEY, OSB No. 04436
Portland General Electric Company
121 SW Salmon Street, 1WTC1300
Portland, OR 97204
Telephone: 503-464-8926
Fax: 503-464-2200
E-Mail: doug.tingey@pgn.com

Exhibit 1

Case Summary

($000)

Total Revenue Requirement	1,810,997
Change in Revenues Requested	
Total Change in Revenues Requested	125,185
Total Change net of RPA	125,185
Percent Change in Base Revenues Requested	7.4%
Percent Change net of RPA	7.6%
Test Period	2011
Requested Rate of Return on Capital (Rate Base)	8.289%
Requested Rate of Return on Common Equity	10.50%
Proposed Rate Base	3,243,601
Results of Operation	
A. Before Price Change	
Utility Operating Income	195,125
Average Rate Base	3,241,594
Rate of Return on Capital	6.02%
Rate of Return on Common Equity	5.96%
B. After Price Change	
Utility Operating Income	268,846
Average Rate Base	3,243,601
Rate of Return on Capital	8.289%
Rate of Return on Common Equity	10.50%
Base Rate Effect of Proposed Price Change	
A. Residential Customers	8.8%
B. Small Non-residential Customers	8.3%
C. Large Non-residential Customers	5.6%
D. Lighting & Signal Customers	2.0%
Note: Percent Changes are on a cycle basis for Cost of Service Customers	

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE _____

In the Matter of the Revised Tariff Schedules for Electric Service in Oregon filed by PORTLAND GENERAL ELECTRIC COMPANY	**MOTION FOR APPROVAL OF PROTECTIVE ORDER** **[EXPEDITED CONSIDERATION REQUESTED]**

Pursuant to ORCP 36(C)(7) and OAR 860-12-0035(1)(k), Portland General Electric Company ("PGE") requests the issuance of a Protective Order in this proceeding. PGE believes good cause exists for the issuance of such an order to protect confidential market information and confidential business information, plans and strategies. In support of this Motion, PGE states:

1. Concurrent with the filing of this Motion, PGE has filed a general rate case.

2. Some of the work papers supporting the rate case filing contain confidential information regarding PGE's natural gas, electric and coal market activities as well as other confidential business matters. This information will include proprietary modeling code, PGE's timing of and expected prices for electricity purchases, PGE's timing of and expected prices for natural gas purchases, PGE's forward position for electricity, PGE's forward position for natural gas, and whether and the amount by which PGE is long or short for electricity and natural gas during various periods in 2010 and 2011. This information is confidential commercial information and/or trade secrets under ORCP 36(C)(7).

3. PGE would like to file with the Commission a complete set of work papers as soon as possible, and requests expedited consideration of this motion.

4. PGE also anticipates that parties participating in this docket will make further requests for confidential information. PGE further anticipates it will be required to file periodic updates containing confidential information in this proceeding.

5. While PGE desires to provide parties with requested information, the information is of significant commercial value, and its public disclosure could be detrimental to PGE and its customers. The information discloses PGE's position, strategy and future needs to purchase and sell electricity, natural gas and coal. If other parties involved in the wholesale electricity, natural gas and coal markets obtained this information, they could use it to the financial harm of PGE and its customers.

6. The Commission should therefore issue a Protective Order to protect the confidentiality of that material. The requested order, identical to the one that the Commission customarily issues, is attached.

For the reasons stated above, PGE requests that a protective order be issued in this proceeding.

DATED this 16th day of February, 2010.

Respectfully submitted,

Douglas C. Tingey, OSB No. 044366
Assistant General Counsel
Portland General Electric Company
121 SW Salmon Street, 1WTC1301
Portland, Oregon 97204
(503) 464-8926 phone
(503) 464-2200 fax
doug.tingey@pgn.com

ORDER NO.

ENTERED

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE ___

In the Matter of the Revised Tariff Schedules for Electric Service in Oregon filed by PORTLAND GENERAL ELECTRIC COMPANY	**ORDER**

DISPOSITION: MOTION FOR PROTECTIVE ORDER GRANTED

On February 16, 2010, Portland General Electric Company ("PGE") filed a Motion for a Protective Order with the Public Utility Commission of Oregon ("Commission"). PGE states that good cause exists for the issuance of such an order to protect confidential business information, plans and strategies. Specifically, PGE states that the workpapers to be filed with its general rate case testimony in this docket will include confidential information such as its proprietary modeling code, timing of and expected prices for electricity and natural gas purchases, and its forward position for electricity and natural gas, along with other confidential information. PGE adds that the public release of such information could prejudice PGE and its customers.

Pursuant to OAR 860-012-0035(1)(k), I find that good cause exists to issue a Protective Order, attached as Appendix A. Under the terms of the order, a party may designate as confidential any information that falls within the scope of ORCP 36(C)(7).

Confidential Information shall be disclosed only to a "qualified person" as defined in paragraph 3 of the Protective Order. Authors of the confidential material, the Commission or its Staff, and counsel of record for a party or persons directly employed by counsel are "qualified persons" who may review confidential information. Other persons desiring confidential information must become qualified pursuant to paragraph 10.

To receive confidential information, however, all parties—with the general exception of Staff—must sign the Consent to be Bound Form attached as Appendix B. This includes the party seeking the issuance of the protective order, because any party may designate information as confidential under this order.

The confidentiality of confidential information shall be preserved for a period of five years from the date of the final order in this docket, unless extended by the Commission at the request of the party desiring confidentiality.

All persons who are given access to confidential information have the duty to monitor their own conduct to ensure their compliance with the Protective Order. Such persons shall not use or disclose the information for any purpose other than the preparation for and conduct of this proceeding, and shall take all reasonable precautions to keep the confidential information secure. If any questions exist as to the status of any person to receive confidential information, the parties may contact the Administrative Hearings Division at (503) 378-6678.

ORDER

IT IS ORDERED that the Protective Order, attached as Appendix A, shall govern the disclosure of confidential information in this case.

Made, entered, and effective on ______________________________.

____
[Judge]
Administrative Law Judge

A party may appeal this order to the Commission pursuant to OAR 860-014-0091.

PROTECTIVE ORDER

DOCKET NO. UE _____

Scope of this Order-

1. This order governs the acquisition and use of "Confidential Information" in this proceeding.

Definitions-

2. "Confidential Information" is information that falls within the scope of ORCP 36(C)(7) ("a trade secret or other confidential research, development, or commercial information").

3. A "qualified person" is an individual who is:

   a. An author(s), addressee(s), or originator(s) of the Confidential Information;

   b. A Commissioner or Commission staff;

   c. Counsel of record for a party;

   d. A person employed directly by counsel of record; or

   e. A person qualified pursuant to paragraph 10. This includes parties and their employees.

Designation of Confidential Information-

4. A party providing Confidential Information shall inform other parties that the material has been designated confidential by placing the following legend on the information:

CONFIDENTIAL
SUBJECT TO PROTECTIVE ORDER

To the extent practicable, the party shall designate as confidential only those portions of the document that fall within ORCP 36(C)(7).

5. A party may designate as confidential any information previously provided by giving written notice to the other parties. Parties in possession of newly designated Confidential

Information shall, when feasible, ensure that all copies of the information bear the above legend to the extent requested by the party desiring confidentiality.

Information Given to the Commission-

6. Confidential Information that is: (a) filed with the Commission or its staff; (b) made an exhibit; (c) incorporated into a transcript; or (d) incorporated into a pleading, brief, or other document, shall be printed on yellow paper, separately bound and placed in a sealed envelope or other appropriate container. An original and five copies each separately sealed shall be provided to the Commission. **Only the portions of a document that fall within ORCP 36(C)(7) shall be placed in the envelope/container**. The envelope/container shall bear the legend:

> THIS ENVELOPE IS SEALED PURSUANT TO ORDER NO. ________ AND CONTAINS CONFIDENTIAL INFORMATION. THE INFORMATION MAY BE SHOWN ONLY TO QUALIFIED PERSONS AS DEFINED IN THE ORDER.

7. The Commission's Administrative Hearings Division shall store the Confidential Information in a locked cabinet dedicated to the storage of Confidential Information.

Disclosure of Confidential Information-

8. Parties desiring receipt of Confidential Information shall sign the Consent to be Bound Form attached as Appendix B. This requirement does not apply to the Commission staff. Confidential Information shall not be disclosed to any person other than a "qualified person," as defined in paragraph 3. When feasible, Confidential Information shall be delivered to counsel. In the alternative, Confidential Information may be made available for inspection and review by qualified persons in a place and time agreeable to the parties or as directed by the Administrative Law Judge.

9. Qualified persons may disclose confidential information to any other qualified person, unless the party desiring confidentiality protests as provided in Section 11.

10. To become a qualified person under paragraph 3(e), a person must:

a. Read a copy of this Protective Order;

b. Execute a statement acknowledging that the order has been read and agreeing to be bound by the terms of the order;

c. Date the statement;

d. Provide a name, address, employer, and job title; and

e. If the person is a consultant or advisor for a party, provide a description of the nature of the person's consulting or advising practice, including the identity of his/her current, past, and expected clients.

Counsel shall deliver a copy of the signed statement including the information in (d) and (e) above to the party desiring confidentiality and to all parties of record. Such notification may be made via e-mail or facsimile. A person qualified under paragraph 3(e) shall not have access to Confidential Information sooner than five (5) business days after receipt of a copy of the signed statement including the information in (d) and (e) above by the party desiring confidentiality.

11. All qualified persons shall have access to Confidential Information, unless the party desiring confidentiality protests as provided in this paragraph. The party desiring to restrict the qualified person(s) from accessing specific Confidential Information must provide written notice to the qualified person(s) and counsel for the party associated with the qualified person(s) as soon as the party becomes aware of reasons to restrict access. The parties must promptly confer and attempt to resolve any dispute over access to Confidential Information on an informal basis before filing a motion with the Administrative Law Judge. If the dispute cannot be resolved informally, either party may file a motion with the Administrative Law Judge for resolution. Either party may also file a motion if the other party does not respond within five days to a request to resolve the dispute. A motion must describe in detail the intermediate measures, including selected redaction, explored by the parties and explain why such measures do not resolve the dispute. After receipt of the written notice as required in this paragraph, the specific Confidential Information shall not be disclosed to the qualified person(s) until the issue is resolved.

Preservation of Confidentiality-

12. All persons who are given access to any Confidential Information by reason of this order shall not use or disclose the Confidential Information for any purpose other than the purposes of preparation for and conduct of this proceeding, and shall take all reasonable precautions to keep the Confidential Information secure. Disclosure of Confidential Information for purposes of business competition is strictly prohibited.

Qualified persons may copy, microfilm, microfiche, or otherwise reproduce Confidential Information to the extent necessary for the preparation and conduct of this proceeding. Qualified persons may disclose Confidential Information only to other qualified persons associated with the same party.

Duration of Protection-

13. The Commission shall preserve the confidentiality of Confidential Information for a period of five years from the date of the final order in this docket, unless extended by the Commission at the request of the party desiring confidentiality. The Commission shall notify the party desiring confidentiality at least two weeks prior to the release of confidential information.

Destruction After Proceeding-

14. Counsel of record may retain memoranda, pleadings, testimony, discovery, or other documents containing Confidential Information to the extent reasonably necessary to maintain a file of this proceeding or to comply with requirements imposed by another governmental agency or court order. The information retained may not be disclosed to any person. Any other person retaining Confidential Information or documents containing such Confidential Information must destroy or return it to the party desiring confidentiality within 90 days after final resolution of this proceeding unless the party desiring confidentiality consents, in writing, to retention of the Confidential Information or documents containing such Confidential Information. This paragraph does not apply to the Commission or its Staff.

Appeal to the Presiding Officer-

15. If a party disagrees with the designation of information as confidential, the party shall contact the designating party and attempt to resolve the dispute on an informal basis. If the parties are unable to resolve the dispute, the party desiring to use the information may move for exclusion of the information from the protection conferred by this order. The motion shall:

a. Specifically identify the contested information, and

b. Assert that the information does not fall within ORCP 36(C)(7) and state the reasons therefore.

The party resisting disclosure has the burden of showing that the challenged information falls within ORCP 36(C)(7). If the party resisting disclosure does not respond to the motion within ten (10) calendar days, the challenged information shall be removed from the protection of this order.

The information shall not be disclosed pending a ruling by the Administrative Law Judge on the motion.

Additional Protection-

16. The party desiring additional protection may move for any of the remedies set forth in ORCP 36(C). The motion shall state:

a. The parties and persons involved;

b. The exact nature of the information involved;

c. The exact nature of the relief requested;

d. The specific reasons the requested relief is necessary; and

e. A detailed description of the intermediate measures, including selected redaction, explored by the parties and why such measures do not resolve the dispute.

The information need not be released and, if released, shall not be disclosed pending the Commission's ruling on the motion.

ORDER NO.

SIGNATORY PAGE

DOCKET NO. UE

I. Consent to be Bound-

This Protective Order governs the use of "Confidential Information" in this proceeding.

_________________________PGE agrees to be bound by its terms of this Protective Order.

By: ______________________________ ______________________________

Signature & Printed Date

____

II. Persons Qualified pursuant to Paragraphs 3(a) through 3 (d)

______________________________PGE identifies the following person(s) automatically qualified under paragraph 3(a) through (d).

______________________________ ______________________________

Printed Date

______________________________ ______________________________

Printed Date

______________________________ ______________________________

Printed Date

______________________________ ______________________________

Printed Date

______________________________ ______________________________

Printed Date

______________________________ ______________________________

Printed Date

III. Persons Qualified pursuant to Paragraph 3(e) and Paragraph 10.

I have read the Protective Order, agree to be bound by the terms of the order, and will provide the information identified in paragraph 10.

By: ______________________________ ______________________________
Signature & Printed Date

____

By: ______________________________ ______________________________
Signature & Printed Date

____

By: ______________________________ ______________________________
Signature & Printed Date

____

By: ______________________________ ______________________________
Signature & Printed Date

____

Table of Contents

I. Introduction

Q. Please state your name and position with PGE.

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

Q. What is the purpose of your testimony and how is it organized?

A. The purpose of my testimony is to:

- Explain the context and objectives for this filing (section II);
- Discuss how our proposals will help PGE meet these objectives, provide financial stability to allow us to make cost effective investments in Oregon's Energy Future that benefit our customers (section III);
- Explain PGE's focus on efficiency and cost effectiveness, the measures we have already taken to reduce the amount of the proposed rate increase, and explain the need for the proposed increase now (section IV); and
- Identify important policy issues and explain our policy recommendations (section V).

My testimony is organized according to these objectives.

II. Context and Objectives

Q. Please summarize this filing's proposed rate impact and its major components.

A. With this filing PGE requests an overall price adjustment of 7.4% effective January 1, 2011. $72 million of the approximate $125 million increase reflects costs related to capital investments needed for PGE to fulfill public mandates and to provide safe, reliable energy that meets our customers' expectations. This includes $29 million for phase 3 of the Biglow Canyon Wind Farm, without which the remaining revenue requirement would yield an overall price adjustment of 5.7%. The balance of the increase reflects O&M costs PGE will incur to support continued and future excellence in customer service, maintain safe, reliable, efficient and effective operations, and respond to regulatory requirements and other external cost drivers such as pension plan funding and health insurance. This case is not about adding more employees. Overall, we project 82.7 fewer full-time-equivalent (FTE) staff positions in 2011 relative to 2008 actual FTE totals. Even after adjusting for Advanced Metering Infrastructure (AMI), PGE's full-time equivalents (FTEs) total is only 33.5 greater in 2011 than 2008, an annual increase of less than 0.5%. The requested change also reflects a two percent reduction in revenue requirement due to projected power costs. As this docket proceeds, we will update our power cost projections.

Q. Are there other important considerations that have impacted this filing?

A. Yes. The current economy and its impact on retail loads is also an important driver of this rate request. If demand for electricity had reached the level projected for the 2009 test year in PGE's most recent general rate case (UE 197), and then PGE experienced a one percent annual growth rate for residential and commercial customers, we would have approximately $54 million in net additional fixed-cost revenues before consideration of the requested increase in this proceeding. This would have reduced the portion of the increase needed for O&M in the case from 5.15% to about 2.0%, and the overall rate adjustment in this case from 7.4% to 4.2%. The present recession has had a significant impact on PGE's revenues without a corresponding reduction in essential system operating costs.

As CEO, I understand that our customers do not want to see the price of electricity increase. However, I also understand that we must have a financially healthy utility to continue to meet the expectations of our customers, investors, and the communities we serve. As you will read in later testimony, we have worked hard to reduce expenses in 2009 and 2010 to manage our operations within available revenues and even with these reductions our earned ROE is less than the allowed ROE. However, the measures we've taken are not sustainable over time without an unacceptable impact on service quality. Further, the deterioration of our financial soundness would ultimately be detrimental to the service our customers expect, and the long-term reliability and cost of electricity. These factors, in combination with the need for continued investment in our system, drive the need for PGE to submit a general rate case at this time.

Q. What do PGE customers expect of their electric utility?

A. Our customers expect high system reliability and power quality. This is true for residential, commercial, and industrial customers alike. While in the past residential customers may have thought of reliability as being primarily a matter of whether the lights go on when they flip the switch, in today's world the interests of residential customers have begun to converge with those of large industrial customers who could lose thousands of dollars from a momentary power fluctuation or surge.

Our customers expect excellent service. Whether they want their power restored after a storm, need to conduct a business transaction, want help figuring out how to be more energy efficient, or simply want to ask a question, our customers expect us to respond promptly, professionally, substantively, thoroughly and courteously. They also expect us to offer multiple alternatives to obtain service, such as electronically or in-person, from one of our customer service representatives. Further, they expect the service to be seamless and of equal quality regardless of what avenue they use to obtain it.

Some of our business customers have moved into our service territory because of the level of service we provide. We need to maintain our service quality to retain these customers and to attract the next generation of new businesses and the jobs they create. This rate request reflects the necessary investments in distribution, transmission, generating resources, infrastructure and O&M to continue to offer good customer service and safe, reliable and responsibly generated energy for our customers.

Q. What else do customers expect from PGE?

A. Our customers expect us to produce and distribute power safely and without harming their quality of life. This is clearly reflected in the regulatory standards public policymakers have adopted to govern our business, and it is reflected in ongoing public policy debates at local, state and national levels. Reduced footprints for carbon and other emissions have increasingly become a national priority. Concern about the environmental impact of power generation is especially relevant here in Oregon and the Northwest. Many residents have made a specific choice to live here based on the region's natural beauty and progressive reputation for environmental stewardship. This is reflected in the high rate of participation in PGE's green power programs (now nearly ten percent, or more than 70,000 customers), which has made PGE the number one utility in the nation for the amount of renewable energy sold to residential customers for each of the past four years. It is also reflected in concern over the impact of our hydro operations on fish runs, interest in emissions reductions at our Boardman plant, and more generally in the focus of public policy discussions surrounding energy issues and energy production in Oregon. Renewable resources, carbon reduction, energy efficiency, and other issues surrounding sustainability, livable communities, and environmental responsibility are all factors that our customers expect us to consider as we make decisions about resource generation and the management of our transmission and distribution systems.

Q. Do customers expect PGE to be a responsible corporate citizen?

A. Yes. Our customers expect us to be a good corporate citizen and to conduct our business with integrity. We share this expectation internally, and diligently comply with rules and regulations enforced by the Federal Energy Regulatory Commission (FERC), the Western Electricity Coordinating Council, the North American Electric Reliability Corporation, and the Securities and Exchange Commission as well as other state and federal agencies such as the Department of Environmental Quality, the Environmental Protection Agency, and the Oregon Occupational Safety and Health Division (Oregon OSHA). Whether specific to our industry or to publicly-traded corporations generally, regulatory requirements have increased substantially in recent years in the form of more aggressive compliance standards and reporting requirements that result in increased compliance costs along with significant fines or penalties for non-compliance.

Q. How significant is the federal regulation of PGE's business?

A. FERC regulation has a broad impact on how PGE conducts its business. PGE is responsible for adhering to the tariffs FERC has approved for PGE's sale of electric transmission, gas transportation, and wholesale electric power. FERC also imposes detailed accounting requirements, and requires PGE to submit financial and performance data to FERC on an annual and quarterly basis. FERC regulates PGE's participation in wholesale energy markets, imposing Market Behavior Rules and policing for energy market manipulation. FERC has detailed records retention requirements that apply to both paper and electronic records, and FERC retains the authority to inspect PGE's books and records. FERC also regulates the reliability of the electric system, and FERC's mandatory reliability standards affect many departments within PGE. This includes newly-effective regulatory requirements around cyber security and critical infrastructure. FERC also licenses and inspects PGE's hydroelectric projects. Finally, FERC has adopted Standards of Conduct that prevent PGE's transmission function from giving preferential treatment to our power marketing function.

Q. Do PGE customers also expect PGE to be efficient and cost effective in all aspects of the business?

A. Absolutely. No one, including me, wants to pay more than necessary for electricity and our customers expect us to be able to demonstrate that we are efficient and cost-effective in our operations and services. Studies that we present later demonstrate that PGE's cost performance is in-line with the industry, but we are making significant efforts to perform better. Details of our efforts in this area are included in later testimony dedicated to this topic (PGE Exhibit 200).

Q. How does PGE know what its customers expect?

A. First and foremost, we operate with very specific and stringent requirements such as Oregon's renewable energy standard as well as service quality standards that are based on our regulators' determination of what our customers want and need; SAIDI (average outage duration per customer), SAIFI (average outage frequency per customer), and MAIFI (momentary outage frequency per customer) standards are set for us and we must meet them or face penalties from regulators as well as likely reductions in customer satisfaction ratings.

Above and beyond these explicit rules delineating what our customers expect, however, we also communicate directly with our 816,000 customers on a monthly basis and we hear back from them frequently. Our customer service representatives handled nearly 1.7 million calls in 2009. Including contacts where our interactive voice response system was able to provide customers with the information they needed or to complete their transaction to their satisfaction, our call center took more than 3 million phone calls over the course of the year. While many of these contacts involve only basic business transactions, our customers also connect with us specifically to register their opinions on issues relating to PGE's operations and activities, or they take the opportunity to comment on these issues when they call us for other reasons.

We also perform quarterly surveys of representative samples of our customers to gauge their level of satisfaction with PGE's service and how they rate us on specific performance measures such as reliability and customer service. The results are compared with those of other electric utilities, and show that PGE is consistently among the top quartile regionally and nationally for customer satisfaction. As noted elsewhere in this testimony, we achieve these results while remaining well within industry norms for efficient and effective use of our resources.

III. This Request Will Help PGE to Satisfy these Important Customer Objectives

Q. How did your preparation of this rate case reflect these customer expectations and concerns?

A. In preparing this rate case, I directed PGE's managers and officers to develop and review their budgets, which form the basis for this rate case, with efficiency and cost effectiveness in mind and with a rigorous focus on serving the needs and priorities of our customers. Managers were told to submit 2010 budgets that were no larger in aggregate (excluding labor escalation and health care increases) than their 2009 budgets (after those 2009 budgets were cut to reflect financial constraints) and to document all changes between 2010 and 2011 with full accounting and explanation for why the change is needed. However, our ability to satisfy our customers' expectations in terms of clearly delineated standards for service quality, reliability, regulatory compliance, and safety is dependent on the outcome of this rate case. In this manner, we believe our request appropriately balances these expectations and costs. We acknowledge that there are other alternatives. Higher quality service levels could be achieved at greater cost; reduced service quality would permit cost reductions but not without compromising reliability and safety. We listen to our customers, and we believe that they want us to continue to offer the same level of service they have come to expect.

Q. How does this filing reflect PGE's customers' priorities?

A. Our filing reflects our customers' priorities and expectations for us as their electric utility by centering on effective and efficient delivery of safe and reliable electric service while seeking to fulfill broader mandates for a changing resource mix, with a smaller environmental footprint, and compliance with all applicable regulations and standards.

PGE has prepared a rate case based on adjustments for several specific investments and expense categories – including costs required for the Biglow Canyon Wind Farm's third phase, costs associated with new emissions control equipment for the Boardman Power Plant, all relicensing costs for our Clackamas River hydro projects, increased capital costs, and essential operations and maintenance costs (especially costs associated with new information technology systems, our generating plants, and regulatory compliance).

Many of these investments and business expenses stem from public mandates such as the Regional Haze Rule, the Oregon Renewable Energy (Portfolio) Standard, FERC licensing requirements, and other regulatory requirements that PGE cannot avoid or delay. They also represent organizational and support mechanisms the company must develop and use to continue meeting our customers' priorities and expectations for service and quality. We need to recover these costs of doing business in our prices. We also seek action on several discrete policy issues, described in detail later in this testimony.

Q. Are Information Technology costs a significant factor in this rate case?

A. Yes. PGE currently operates a large number of legacy IT systems developed and deployed for different business units over the course of the past 30 years. Many of these systems are nearing obsolescence, and are no longer supported or will soon be unsupported by the vendors that supplied them. At the same time, technological advances and the expectations and practices of both our industry and our customers have created a need for new functionality, services and interfaces – while maintaining IT security. This has created circumstances where PGE must incur increasing costs to maintain and expand existing systems when better systems that are specifically tailored to meet the needs of our industry are now readily available in the marketplace and can be deployed throughout the enterprise to improve efficiency and effective management of data and information.

In response, PGE has initiated a long-term strategy to upgrade its IT systems, called the 2020 Vision strategy. This strategy aims to dramatically reduce the number of systems we operate, improving our processes, security and cost-effectiveness for both employees and customers. This initiative will be completed over the course of the next ten years. The 2020 Vision strategy is discussed fully in PGE Exhibit 600.

Q. Will the result of this rate request affect PGE's ability to access capital to fund investments in the years immediately following the 2011 test year?

A. Yes. While current revenue needs alone would justify our request, another key consideration in this rate case is the need for extensive capital investments during the several years immediately following the test year, as envisioned in our Integrated Resource Plan (IRP) that is currently under review by the Commission. These include: (1) acquisition of new renewables for PGE to comply with the state’s renewable portfolio standard requirements in 2015, (2) the Cascade Crossing transmission line to reduce congestion and provide pathways for new power sources, (3) additional gas-fired resources to help meet growing loads and backfill expiring long-term hydro contracts, (4) back up of intermittent wind and solar power, and (5) new smart grid infrastructure to support demand side resources and acquisition of additional energy efficiency.

Naturally, these specific investments are contingent on Commission acknowledgement of our IRP and the subsequent results of bidding processes with independent review. However, significant capital expenditures will be required in the near future under any scenario due to load growth projections and the requirements of changing infrastructure needed to serve our customers. We have a responsibility to position PGE so that it can minimize the cost of capital to make those investments for customers.

Q. Why should the need for future capital investments be considered in the 2011 rate case when they're not part of the 2011 test year?

A. In short, the 2011 rate case will set the parameters for current and prospective debt and equity investors evaluating PGE. If investors believe that the utility is financially sound and positioned with a fair opportunity to recover its costs, as evidenced by strong investment grade bond ratings and other market indicators, we will be able to finance our necessary future capital investments at a lower long-term cost to customers.

However, the company's current price structure does not support a reasonable rate of return for investors in PGE bonds and equity. Without the opportunity to earn a fair rate of return, our access to capital (on competitive and reasonable terms) to build or purchase under contract the necessary infrastructure may be jeopardized. We need to demonstrate to investors, in advance of many of the major capital investments called for in our resource plan, that PGE can be expected to recover both the cost of these major investments and the cost of ongoing operations and maintenance to operate the system. Today investors have many choices, both within and outside the utility industry. If PGE cannot earn a fair return then investors will invest elsewhere. Further discussion of these issues is included in later testimony on PGE's expected cost of capital (PGE Exhibit 1100).

IV. Efficiency and Cost Effectiveness, Rate Mitigation, and the Risks of Delay

Q. Isn't cost control also important to both customers and investors in considering the value they can expect to receive from PGE?

A. Yes. As noted above, PGE customers and investors expect the utility to be efficient and cost effective in its operations.

It is always a priority for PGE to ensure that the expenditures we make on our customers' behalf are prudent and cost effective. However, economic conditions over the past two years in Oregon have made it even more imperative for PGE to scrutinize its operations and the components of this rate case to assure our customers and our regulators that the costs we seek to recover are reasonable. Our customers, investors and regulators need to be confident that we have systems and controls in place to maintain a true culture of cost efficiency.

FERC Form 1 data and independent analysis confirm that PGE's costs are well within the norm for comparable utilities in our region. This is discussed further in PGE Exhibit 200.

Q. Are efficiency and cost effectiveness issues in which you have taken a personal interest?

A. Yes. After my appointment as President and CEO in January 2009, I worked with PGE officers and managers to begin a company-wide program review and process improvement initiative aimed at finding ways for PGE to further improve cost efficiency in its operations. We have also presented testimony (PGE Exhibit 200) in this rate case to further discuss PGE's efficiency and cost effectiveness efforts.

Q. Could you summarize that testimony?

A. Yes. The testimony on efficiency and cost effectiveness illustrates three essential points:

- As previously noted, PGE's O&M costs are well within the norm for similar utilities. Our costs are typically in line with our peers as demonstrated by data collected from FERC Form 1 filings and confirmed by a recent utility benchmarking study performed by the Pacific Economics Group (PEG).

- These results do not reflect a sudden change of course on cost control. While I have placed increased emphasis on efficiency and cost effectiveness during the past year, PGE already has a history of cost consciousness and comprehensive initiatives to reduce and manage costs through system efficiency upgrades, process improvement, leveraging technology, and other efficiency programs.
- That said, no large organization can ever afford to take efficiency for granted. We listened to stakeholder concerns as expressed in testimony filed by interveners in our 2009 rate case (UE 197), and we've responded to the realities of Oregon's economy. The result is a company-wide program to further streamline our operations and capture additional cost savings without compromising our level of service, safety and reliability.

Q. Has the company already taken measures in this request to reduce the price impact on our customers?

A. Yes. We have taken two major, concrete steps to reduce the price increase. First, our ROE testimony in this rate case includes an independent evaluation showing that PGE would be justified in seeking an allowed ROE of 11%, based on the elements included in this case, to assure an opportunity for returns comparable to those offered by our peer utilities. However, we are requesting a 10.5% ROE instead, because we recognize that in the current economic climate the lesser allowed rate of return better reflects the needs of our customers, but still provides a fair investment opportunity to our shareholders. This reduced our request by $13 million.

Second, for the same reason, PGE has chosen not to request recovery of any of the cost of our officer incentive plan and only 50% of our employee incentive programs in this rate case. Here again, we believe the full costs of these incentive programs are entirely justified as part of a competitive compensation package to attract and retain an outstanding workforce that will produce excellent results and provide outstanding customer service. Our customers are ultimately the beneficiaries of these incentives through continuous quality improvements. Furthermore, long-term curtailment of these programs could have very real negative consequences for customers by reducing PGE's ability to compete for qualified and dedicated employees. Yet to mitigate the proposed price increase we have not requested full recovery for the prudent cost of these programs. This reduces our request by approximately $10 million.

Q. What would be the consequences of delaying this rate case?

A. In a sense, we had a preview of the consequences in 2009. In that year, we were forced to make temporary O&M budget cuts that are not sustainable over the long term if we are to meet regulatory standards and our customers' expectations. An example of this is our tree trimming program, which we cut by $1.3 million to the level approved in our last rate case. However, we cannot continue the program at that level without undermining our ability to meet reliability and safety standards. Inadequate cost recovery and volatile earnings in 2009 also contributed to circumstances under which the company was obliged to issue equity at a price significantly below the book value in order to finance essential infrastructure investments such as Biglow Canyon phase 2.

These developments – unsustainable cost cuts and issuing equity at prices below book value – undermine our long-term financial stability and soundness that provides a necessary platform to offer safe, reliable energy that meets our customers' expectations and to have access to capital markets at fair and competitive rates.

Q. Is the quality of PGE's operations and service important to Oregon's economic future?

A. Yes. The present economic downturn will not last forever, and the region's electric utilities must be positioned to respond to the growing needs of a recovering economy as it occurs. PGE is an active partner in Oregon's economic development efforts, helping to attract, retain, and grow businesses that constitute the engine of our economy, including high tech companies, green businesses, and manufacturing concerns. The quality and reliability of electric service is a key factor of many of these employers in their decisions to locate in our service territory. PGE works closely with the state, local governments and the broader business community to help prospective customers understand what we can offer to help them succeed. We have an obligation to our customers and the communities we serve to protect the strength of our system and our business as an essential component of our state's economic infrastructure, and we believe this rate case is a key requirement in that effort.

V. Policy Issues

Q. What are the policy objectives to be resolved in this rate case?

A. In addition to the infrastructure investments and other cost components previously addressed, we have several specific policy objectives in this rate case that are addressed in testimony because they require action by the Commission. PGE seeks approval of the following:

- A pension automatic adjustment clause tariff to forecast pension expense, track and amortize differences between expected and actual pension expense, and recover financing costs associated with net pension-related cash flows (PGE Exhibit 500).
- A balancing account for tracking and recovery of costs associated with future major storm damage. PGE formerly purchased insurance coverage for major storm damage. We can no longer obtain storm insurance at a reasonable cost, so we propose an accounting Order to establish a storm damage balancing account to track differences between an annual accrual of $3.5 million and actual storm damage costs for level 3 storms (PGE Exhibit 800).
- Continuation of the Power Cost Adjustment Mechanism (PCAM) and Automatic Update Tariff (AUT), with alteration of the PCAM to make the deadbands symmetrical and narrow their overall size to $10 million. PGE also proposes to include collateral costs associated with power supply operations as net variable power costs for ratemaking purposes and include them in the PCAM/AUT going forward. We believe appropriate alterations of the PCAM/AUT along these lines

are essential in order to provide cost recovery structures comparable to those prevalent throughout our industry (PGE Exhibit 400).

- An automatic adjustment tariff related to recovery of our remaining investment in the Boardman Power Plant to align recovery with a Commission decision to alter the operating life of the facility (PGE Exhibit 300).
- An accounting Order that allows PGE to track differences between the environmental mitigation and remediation costs as projected in this case for certain established projects and the corresponding actual costs (PGE Exhibit 700).
- An accounting Order that allows PGE to accrue long-term debt costs on study costs of self-build options for IRP/RFP purposes. In addition, we request that the Commission allow PGE to create a future regulatory asset if we select an alternative project to a self-build option (PGE Exhibit 300).
- An accounting Order that allows PGE to smooth the impact of O&M costs related to the Information Technology (IT) system replacement program (2020 Vision) (PGE Exhibit 600).
- Continuation of the decoupling mechanism approved by the Commission as a two-year pilot in UE 197 (PGE Exhibit 1500).

We also provide testimony describing $16.5 million in savings associated with automated metering infrastructure (smart meters), and, as noted above, dedicated testimony to address PGE's commitment to cost efficient operations and management. These testimonies help provide important context for the Commission's review of the policy decisions and objectives described in this filing.

VI. Conclusion

Q. Why is PGE filing this rate case at this time?

A. This rate case filing is about what kind of utility PGE will be tomorrow. It is about providing PGE the appropriate resources we need to offer our customers the service quality and reliability they expect in the future. It is about establishing a foundation for making future investments that will allow us to cost effectively meet our customers future energy needs in a reliable, safe manner within changing environmental standards. This rate request demonstrates our commitment to do all these things, consistent with our ongoing culture of efficiency and cost effective operations, while providing appropriate levels of service and value to customers.

VII. Overview of PGE's Testimony

Q. In addition to this testimony, what other testimony is presented in this case?

A. PGE is presenting the following direct testimony:

Exhibit 200 summarizes PGE's cost efficiency efforts and provides the results of studies performed to evaluate PGE's costs compared to other utilities. In addition, the testimony describes PGE's proposed changes to the structure of the PCAM.

Exhibit 300 summarizes PGE's requested revenue requirement for the 2011 test year. In addition, the testimony provides PGE's estimate of savings associated with AMI during the 2011 test year, and provides the basis for PGE's request for an accounting Order to accrue long-term debt costs on preliminary study costs related to IRP projects. Finally, the testimony summarizes the estimated impact of Biglow Canyon phase 3 in the 2011 test year.

Exhibit 400 supports PGE's initial estimate of Net Variable Power Costs (NVPC) for the 2011 test year, and presents certain changes to the Monet model to forecast costs. In addition, the testimony, along with Exhibit 1100 below, describes PGE's request to treat collateral costs related to power operations as NVPC for ratemaking purposes.

Exhibit 500 describes PGE's compensation philosophy and presents the projected 2011 test year costs for wages/salaries, benefits, and incentive compensation. The testimony also describes changes to certain compensation programs since UE 197. Finally, the testimony describes the current circumstances PGE faces with regard to pension costs and funding and proposes an automatic adjustment clause tariff to track and update actual pension related costs.

Exhibit 600 describes the current Information Technology (IT) environment and provides detail on the drivers of cost changes in IT. In addition, the testimony describes the cyber security project and the 2020 Vision initiative, in which we seek to replace and consolidate the significant number of software packages PGE uses to perform essential work. Finally, the testimony provides the basis for requesting an accounting Order from the Commission to help smooth the impact of development O&M on customer prices.

Exhibit 700 summarizes PGE's resource base and describes the fixed O&M and capital costs associated with PGE's plant and power operations areas. In addition, the testimony supports PGE's efforts in the area of environmental mitigation and hydro relicensing. Regarding the former, the testimony provides the basis for requesting an accounting Order to track differences between forecast and actual environmental mitigation projects.

Exhibit 800 supports PGE's efforts in the delivery function, explaining PGE's test year forecast of T&D O&M non-labor costs and capital expenditures. In addition, the testimony describes and supports the need for a major storm damage balancing account and accrual mechanism, replacing PGE's previous reliance on storm insurance

Exhibit 900 supports PGE's customer service activities for the 2011 test year, including O&M non-labor costs and PGE's estimated uncollectible rate for the 2011 test year.

Exhibit 1000 describes cost increases in PGE's corporate support functions, or A&G, including insurance, R&D, and the WECC membership, as well as some environmental costs not supported in PGE Exhibit 700.

Exhibit 1100 supports PGE's forecasted cost of capital for 2011. It discusses PGE's cost of long-term debt and risk, and supports PGE's proposed capital structure.

Exhibit 1200 addresses PGE's equity costs, applying the Discounted Cash Flow and Risk Premium models to support an 11.00% return on equity. However, as I noted earlier, I have directed management to use a 10.50% ROE for filing this case.

Exhibit 1300 provides testimony explaining why the current structure of PGE's PCAM differs from mainstream regulatory practices and places PGE at a disadvantage, relative to our competitors, in accessing capital at reasonable rates. The testimony also provides the basis for an appropriate PCAM framework supporting recovery of prudently incurred fuel and purchase power costs.

Exhibit 1400 explains PGE's load forecast. PGE forecasts that 2011 total deliveries to customers will be essentially flat relative to the 2009 weather-adjusted level.

Exhibit 1500 presents PGE's proposed price changes, proposed tariff changes to Schedule 125 (Annual Power Cost Update) and Schedule 126 (Power Cost Adjustment Mechanism) consistent with prior testimony. In addition, the testimony supports an updated marginal cost study, ratespread, and rate design that serve as the basis for the proposed prices. The testimony also provides support for the continuation of PGE's decoupling mechanism. Finally, the testimony presents three new tariffs: 1) Schedule 141 related to pension recovery, 2) Schedule 145 related to Boardman operating life, and 3) Schedule 85, a new schedule for large commercial customers between 201 kW and 1000 kW.

VIII. Qualifications

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

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

Q. Does this conclude your testimony?

A. Yes.

Table of Contents

I. Introduction

Q. Please state your name and position with PGE.

A. My name is Maria M. Pope. I am the Senior Vice President, Finance, Chief Financial Officer and Treasurer for PGE. My qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss PGE's efficiency and cost effectiveness efforts. I also propose changes to PGE's power cost adjustment mechanism. With regard to the efficiency and cost effectiveness portion, my purpose is to:

- Discuss and provide examples of PGE's ongoing commitment to efficiency and cost effectiveness and future plans to improve; and
- Compare our operational costs with other utilities.

Q. Why are you providing this efficiency and cost effectiveness testimony now?

A. We are providing this testimony now for several reasons. First, we believe parties expect PGE to describe its efforts to gauge and improve efficiency and cost effectiveness. Second, we realize that we need to do a better job documenting and communicating to our customers, regulators, and the public the many cost efficient and innovative operational improvements PGE is undertaking. Finally, the external environment is changing, which requires that we intensify our efforts to respond to new environmental, economic, technological and other external changes. The changing environment presents an opportunity to examine the requirements of our work and our performance.

Q. Please explain what you mean by efficiency.

A. Efficiency is aimed at how we deliver reliable energy and service to customers while maintaining standards for safety and regulatory compliance. Technically, efficiency is measured by comparing the ratios of output to input. A system increases its cost efficiency when it maintains output with fewer or less costly input(s), or conversely delivers higher value to customers for the same or lower cost. Our efficiency and cost effectiveness efforts aim to contain or reduce costs while keeping our high quality of customer service and system reliability. We are not effective if our system is not safe, not reliable, or we are not providing good customer service. This differs from mere cost cutting; obtaining the lowest absolute cost is not a responsible goal if it sacrifices our effectiveness in delivering safe, reliable power.

Q. Why is efficiency and cost effectiveness important?

A. Efficiency and cost effectiveness are an important part of our culture at PGE. Efficiency and cost effectiveness means our customers are getting more for their money. Customers expect us to do whatever we can to keep costs down while delivering safe, reliable power and good customer service. This is especially important as our customers are beset by the recessionary economy. For employees, working for an efficient organization is a source of pride.

II. Establishing a Culture of Efficiency and Cost Effectiveness

Q. You stated the external business environment is changing, how are you responding?

A. We are embarking on a new phase of efficiency and cost effectiveness. Historically, many business units within PGE have implemented efficiency and cost improvements, often in partnership with another business unit with which they share a common process. Our renewed commitment to efficiency and cost effectiveness starts with a more centralized corporate focus and organization to drive improvements at an overall corporate level, setting standards and expectations, providing resources, sharing examples, and monitoring and reporting on improvements. The approach of reinforcing a culture of improvement and efficiency is distinct from mere budget cuts. We have implemented budget cuts as a short-term, temporary solution to a changing economic environment, but these cuts do not reflect efficiency gains. See PGE Exhibit 100. Budget cuts of this type do not reengineer business processes by design and may create inefficiency if there is no change to underlying processes.

Q. Please describe the new phase to enhance PGE's culture of efficiency and cost effectiveness.

A. The new phase is being led by a team with corporate-wide focus, the Corporate Performance Management group,[1] the manager of which reports directly to me. The corporate-wide efficiency charge builds on the proven track record of this group's previous work with the Customer Service and Delivery organization. The group is responsible for working with functional areas across PGE, assisting them with establishing meaningful performance measures, benchmarks, best practice applications, and providing project management and

---

[1] The Corporate Performance group was assembled from existing employees from Customer Service and Delivery. See PGE Exhibit 1000, Corporate Support, Table 1.

process improvement services. The group is also charged with assisting management in refining performance measurement and targets. The group has set up a Sharepoint intranet site, entitled "Company Improvements," to share efficiency and benchmarking examples company-wide. The site enables all employees to post their own efficiency and cost effectiveness, and benchmarking examples and to read others. This approach creates an informal network for managers to learn from each other, encourage employees to suggest improvements, and drive improvement throughout PGE.

The Corporate Performance Management group is also working to develop an enterprise-wide benchmarking strategy and will identify industry best practices to further our continuous improvement culture. The goal is to benchmark key performance metrics in conjunction with any new system implementation to establish a baseline and inform the design of the new system. Benchmarking is the first step; the value creation is in the improvement work that follows.

Q. How is this different from what you have been doing?

A. We are instituting a renewed corporate focus to lead, coordinate, and facilitate efficiency improvements throughout the company. In the past, efficiency efforts were primarily undertaken at the business unit level and not necessarily shared or coordinated company-wide. Some managers had the skills and resources to drive cost efficiencies and process improvements, while others did not.

A. Initial Measurement of PGE's Costs Relative to Others

Q. Has PGE evaluated its costs relative to others?

A. Yes. PGE has performed cost comparisons by comparing PGE's FERC Form 1 costs with the Western Electricity Coordinating Council (WECC)[2] and NW Utilities[3] annually. The FERC Form 1 analyses compare the cost of performing sets of activities related to the standard utility functions with other utilities and industry groups on a per customer or per kWh basis. In addition, we recently retained the Pacific Economics Group (PEG), which uses an econometric modeling approach that goes a step further by identifying utility O&M cost drivers.

Q. What is the difference between cost comparisons and benchmarking?

A. We make a distinction between cost comparisons and benchmarking. The cost comparisons stop at the comparison and do little to explain the factors causing discrepancies and identify areas for improvement. Also, cost comparisons do not help identify best practices to inform improvement.

In contrast to the cost comparison snapshot approach, benchmarking takes the process further to identify reasons, including operational strengths and areas for improvement, for a given performance, and help identify best practices. Once the performance baseline is known, managers can target areas for improvement, establish better metrics, implement changes, and measure and monitor the effects of changes on performance. Benchmarking is an ongoing process, not an event.

---

[2] The WECC utilities include: Arizona Public Service Company, Avista Corporation, Black Hills Power, Inc., El Paso Electric Company, Idaho Power Co., Nevada Power Company, NorthWestern Energy Division, Pacific Gas and Electric Company, PacifiCorp, Public Service Company of Colorado, Public Service Company of New Mexico, Puget Sound Energy, Inc., San Diego Gas & Electric Co., Sierra Pacific Power Company, Southern California Edison Co., Tucson Electric Power Company, and PGE.

[3] The NW utilities include: Avista Corporation, Idaho Power, NorthWestern Energy Division, PacifiCorp, and Puget Sound Energy, Inc.

Q. Explain further what you mean by comparing utility functions.

A. The FERC Form 1 and PEG comparisons focus on costs for PGE to perform activities related to a particular high level function, (e.g. Distribution O&M), against another utility or industry group. In both the PGE internal and PEG analyses, information from FERC Form 1 data is used. These approaches provide snapshots of PGE's costs relative to a group of peers.

Q. What did you learn from the FERC Form 1 comparisons?

A. Figure 1 below provides a cost comparison of aggregated Administrative and General (A&G), Distribution O&M, Customer Accounts and Service (Customer Service Costs) on a per customer basis for PGE, NW Utilities, and WECC utilities for 2006-2008. These represent our major O&M cost components except for Generation O&M and Transmission O&M.[4]

Figure 1

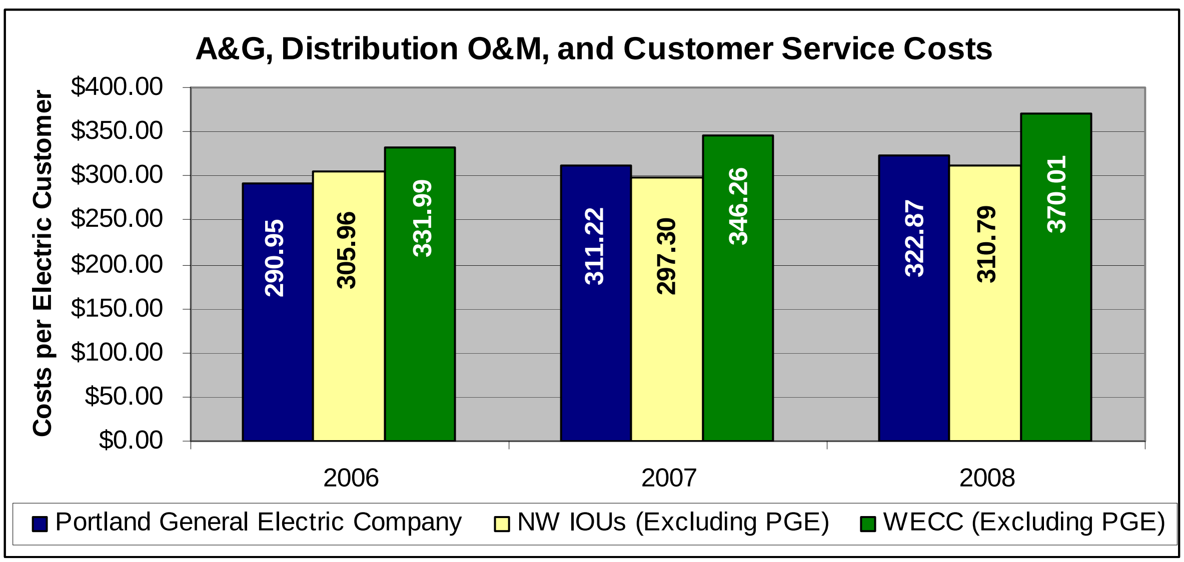
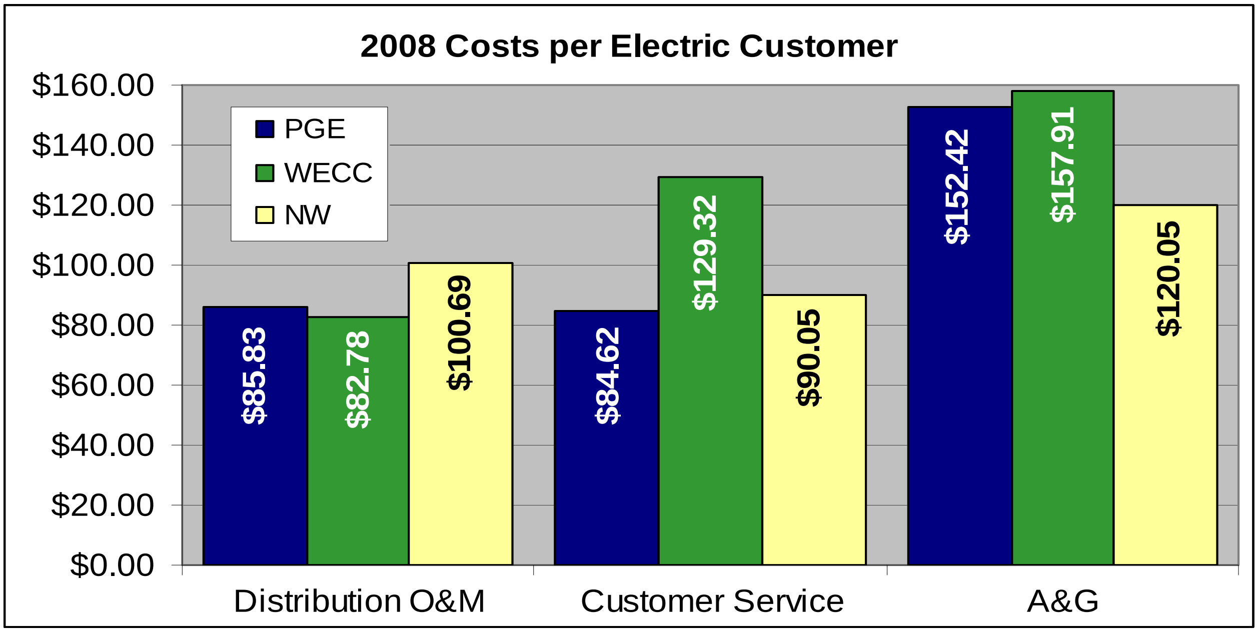


Figure 2 provides a snapshot of the most recent data (2008) and breaks out the functional areas compared.

---

[4] We have excluded Transmission because we have fewer transmission investments than other utilities in our region. In addition, we excluded Generation O&M because it is highly dependent on the particular generation fleet of a utility, making comparisons very difficult.

Figure 2



Q. What are the limitations of the FERC Form 1 comparisons?

A. The FERC Form 1 analysis, while one indicator, has some shortcomings and does not tell the full story of effectiveness and cost. The FERC Form 1 analysis does not measure the quality of the outputs such as customer service, safety and reliability. In addition, utilities do not account for all costs in the same way. Overhead costs may be allocated to functional areas by some and not by other utilities. Each utility has its own set of unique circumstances based on its particular physical, economic, and regulatory environment. For example, some utilities conduct their own energy efficiency programs and their costs of doing so are included. In Oregon, programs are conducted by the Energy Trust of Oregon (ETO). Another example of noncomparability is in tree trimming costs which, in wet climates are usually higher than for utilities in more arid regions.

Q. If this is the case, are these studies relevant?

A. FERC Form 1 comparisons provide an indication of what categories of costs may deserve additional analyses and evaluation. Disparate trends may indicate further research is needed. To delve deeper into comparing our O&M costs with others, we retained PEG to apply their econometric modeling approach and compare our total O&M costs.

Q. Who is the PEG and what is their expertise?

A. PEG is a research group that specializes in statistical cost research for the energy utility industry. A number of entities including utilities, regulators, and industry groups, have retained PEG to testify, prepare papers, and teach performance benchmarking. Among their client list are: the Louisiana and Michigan Public Service Commissions, Edison Electric Institute, Electric Utility Consultants, Inc. (EUCI), Wisconsin Public Utility Institute, Michigan State University Public Utilities Institute, Center for Regulatory Studies, Oklahoma Gas and Electric, Hawaiian Electric, Central Vermont Public Service, Canadian Electricity Association, Ontario Energy Board, and other international clients.

Q. Describe the approach taken by the PEG and how it is useful in measuring utility performance.

A. PEG's approach uses an econometric model that goes a step further than the FERC Form 1 functional cost comparisons. The econometric model was based on a sample of data for 105 U.S. power distribution and 54 power generation companies.

In developing its model, PEG attempts to identify the overall drivers of a utility's costs for all the utilities in the sample. The model is equipped to take into account, for example with distribution O&M, labor prices, material and service cost, and also business condition variables that affect the cost of providing distribution services like the extent of a system's overhead lines. The extent of overhead facilities affects distribution O&M costs because lines are more exposed to weather challenges and trees. Please see PEG report for more information on variables and the econometric modeling approach, included as PGE Exhibit 201.

The model compares PGE's costs from FERC Form 1 and also includes the business condition variables to predict a cost benchmark where PGE's costs should be relative to the peer group. A negative score and high confidence level means that PGE is better than the peer group in that functional cost category. A positive score and high confidence level means that PGE is worse than the peer group in that functional cost category.

Q. Did PEG perform benchmarking?

A. Not in the full sense of the concept as explained earlier. While often referred to as "statistical benchmarking," we see it as a more sophisticated cost comparison approach that provides us more information on cost drivers when we compare our performance to others. It did not attempt to explain the difference between PGE's performance and other utilities. It does, however, give us key cost driver data to examine as we delve deeper into reasons behind our standings.

Q. Which components of PGE's operations did PEG address in its comparisons?

A. We asked them to focus on three areas concerning efficiency and cost effectiveness:

- 1) O&M expenses in Distribution, Customer Accounts and Service, and A&G (DCA) on an aggregated basis;
- 2) Non-fuel Generation O&M; and
- 3) Reliability using the System Average Interruption Duration (SAIDI)[5] and System Average Interruption Frequency Indices (SAIFI).[6]

[5] SAIDI is the total time, in a year, without power for the average customer, measured in minutes. It is an indicator of system reliability. All planned and unplanned interruptions of five minutes or more are included in the calculation. Major events are excluded. PGE's goal is fewer than 90 minutes.

[6] SAIFI is the frequency, or how often the average customer loses power, measured in times per year. All outages affecting one customer or more, lasting five minutes or more, are counted. Major events are excluded. PGE's goal is fewer than 1.2 times.

We did not include Transmission O&M because of our small investment in this part of the business.

Q. What are the key empirical results of the econometric modeling?

A. The results were as follows:

- DCA: PGE's DCA costs are approximately 11% below the model's prediction on average from 2006-2008. However, at the 90% confidence level, PGE's costs are not statistically different from the average over the period.
- Generation: PGE's generation O&M yielded a similar result, and was found to be 5% below the econometric cost model's prediction on average from 2006-2008. At the 90% confidence level, PGE's generation costs are not statistically different from average costs over the period.
- Reliability: With regard to SAIDI and SAIFI, the results of the statistical benchmarking mean that PGE's reliability performance is "significantly superior," with both the SAIDI and SAIFI results far below the cost benchmarks on average from 2006-2008, at 67% and 48% respectively. To ensure that similar outage and frequency measures are used to compare reliability performance, PEG used only the SAIDI and SAIFI indices, which are based on the Institute of the Electrical and Electronics Engineers (IEEE) standards. While Oregon holds PGE to a higher standard than the IEEE standard, we provided the IEEE based SAIDI and SAFI data to PEG so "apples to apples" comparisons could be made. Please see PGE Exhibit 800 for discussion of PGE's Reliability Service Quality Measure.

Q. What conclusion do you draw from the results?

A. Similar to the FERC Form 1 results, the PEG results show that we match up well with the industry on DCA and generation and are performing in the superior category for reliability, while keeping our reliability related costs in line with the industry.

- DCA: PGE's aggregated O&M costs are in line with industry standards, with which we match up well in terms of average O&M costs. Despite matching up well on O&M costs, we are still driven to improve our efficiency and cost effectiveness. Business conditions and requirements are always changing which requires ongoing review of the work (how it is done, the costs, and the effectiveness). We are not satisfied with being in line with the industry. We want to continuously improve.
- Generation: PGE is in line with the industry according to the PEG analysis. We note that while the model for non-fuel Generation O&M takes into account several generation cost drivers, O&M costs vary significantly with the type and age of plants owned by a participating utility. In addition, it is difficult for a model such as PEG's to capture the impact of significant unique attributes that may influence generation O&M, such as the relatively low capacity factors for thermal plants in the Northwest due to the impact of spring hydro runoff. While we include the results for completeness, we do not believe that the Generation results are as meaningful as the analysis of Distribution, Customer Accounts and Service, and A&G.
- Reliability: PEG terms our reliability results "significantly superior." Our SAIDI and SAIFI performance indicates that we are achieving a very high level of reliability at industry average cost levels. We have focused on system reliability because we know it is important to customers. Customer satisfaction with

reliability is evidenced in recent residential, industrial and general business customer satisfaction surveys. The 2009 JD Power Residential customer surveys indicate a high level of satisfaction with PGE's power quality and reliability, placing PGE in the top quartile of performance, or "elite" category, for utilities across the country.[7] PGE's largest industrial customers also give PGE high marks for reliability. In the 2009 TQS Research, Inc. study of the largest energy users (over 1000 kw), PGE ranks 11th out of 58 utility holding companies nationally on industrial customer satisfaction with reliability, with 86.6% of respondents very satisfied[8] and another 11.9% somewhat satisfied. In the same survey, PGE ranked 10th out of 58 on minimum outages.[9] Similarly, our general business customers give PGE high marks for reliability and customer service. In the 2010 JD Power survey, general business customers ranked PGE's power quality and reliability first in the region and seventh nationally out of 82 utilities. We are achieving high reliability marks according to our customers and compared with other utilities, and we are in line with average industry costs.

Q. What are your next steps for further cost analysis and improvement?

A. The next steps are being led by our Corporate Performance Management group, discussed earlier. The group is working with officers and managers to set forth an organizational

[7] The JD Power ranking for reliability relates to the following components: supplying electricity during very hot and very cold temperatures, avoiding power interruptions of five minutes or less, avoiding outages of more than five minutes, keeping customers informed of an outage, promptly restoring power after an outage, and providing quality power without spikes, drops or surges.

[8] The components of overall reliability in the TQS Survey include: keeping unplanned outages to a minimum, keeping outages lasting less than a minute to a minimum, coordinating planned outages with customers, timely restoration of power, being easy to contact and get information during an outage, and number of times the customer lost power due to unplanned outages.

[9] Other results in the TQS survey related to reliability include the following PGE rankings: 4th out of 58 on how well PGE coordinates outages with the industrial customer's operations; 10th out of 58 on restoration; 3rd out of 58 on ease with which the customer can reach PGE during an outage; 4th out of 58 on outage information, and 10th out of 58 on satisfaction with overall power quality.

benchmarking plan over a multiple year cycle. The plan will focus on areas of PGE that are key performance contributors. Over a cycle of four to five years, nearly every area of PGE will have an opportunity to participate in a targeted benchmarking study. We will also benchmark areas selected for large system upgrades as a way to improve the system design. The goal is a cycle of benchmarking and continuous improvement, reinforcing our corporate culture of efficiency and cost effectiveness.

Q. What strategic benchmarking is PGE planning?

A. In 2010, our strategic benchmarking is focused on the replacement of the finance and accounting system, the first system to be replaced as part of PGE's 2020 Information Technology Initiative, also known as "2020 Vision." Please see PGE Exhibit 600, Section IV, Part B, for more information on this initiative. Prior to replacement, PGE is benchmarking key processes and functions to identify performance metrics, determine best practices, and have the best practices inform the design of the finance and accounting system. Once the finance and accounting system is designed, constructed, and implemented, PGE's costs and performance will be reviewed against best industry practices, helping managers identify areas for process improvements.

Q. Has PGE performed any other benchmarking?

A. Yes. In an internal 2009 survey, twenty-two PGE business units reported they are either currently participating or have recently participated in "benchmarking" studies. Many of these may be comparison and not benchmarking studies. These units include: sourcing and contracts, fleet and transportation services, safety and health, internal audit, customer satisfaction, and compensation and benefits. Many of the reported "benchmark" studies are directed at outputs like customer satisfaction, customer ease of navigation on PGE's Web site, market compensation data, and employee accident rates. Sometimes the studies were undertaken to identify PGE's performance or costs and to trend these relative to others, and other studies identified best practices, (e.g., customer satisfaction studies and ease of access to web studies). We expect comparison and benchmarking studies at the business unit level to continue. An inventory of survey responses is attached as PGE Exhibit 202.

B. Examples of System Efficiencies

Q. Does PGE have any large scale projects leading to efficiencies?

A. Yes. Recent large scale projects include:

- Automated Metering Infrastructure (AMI): The current project to replace all of our electric meters with smart meters will yield significant annual operating benefits, approximated at $16.5 million for 2011. We estimate approximate capital cost of about $132 million for this project. Future operating benefits could be higher. In addition to these benefits, it also lays the foundation for customer and system benefits from additional programs that will take advantage of the technological platform and new information the AMI system provides. For a list of the customer and system benefits envisioned, please see PGE Exhibit 300, Section III, Part C. AMI is an example of increasing both the efficiency and effectiveness of the system.
- Boardman Upgrades: In 2000 and 2004, PGE replaced the low pressure and high pressure/intermediate pressure turbines at Boardman at a cost of $16.8 million. PGE chose to upgrade the turbines to enable the plant to capture more energy from the same amount of fuel and further increase output. After the turbines were installed, electricity output at Boardman increased by about 35 MW from the 2000 upgrade and 32 MW from the 2004 upgrade for the same fuel input. (PGE's share was 22.75 MW and 20.8 MW, respectively). The increased energy output

of both upgrades represented an improvement of approximately 12% in efficiency and output. At today's power market prices and based on PGE's 65 percent share of the plant's power output, this is a savings of $15.6 million annually.[10]

- Coyote Springs Upgrade: Included in this filing, (see PGE Exhibit 700), is a project to upgrade Coyote Springs. The upgrade will result in approximately 15 MW additional capacity and an improved plant heat rate, thus reducing power costs. The upgrades will reduce inspection requirements and extend the life of the rotors for more reliable operation. A new control system permits a larger plant operating range and more dispatch flexibility which can aid in the integration of wind resources into the PGE system.
- Taxes:
    - Sherman County Property Tax Savings: The decision to site Biglow Canyon Wind Farm in Sherman County produced a savings of $30-$40 million in property taxes over 15 years, starting in 2008, through Sherman County's Strategic Investment Initiative. For further discussion, please see PGE Exhibit 300.
    - Columbia County Property Tax Savings: The decisions to locate Port Westward in a Columbia County enterprise zone and hire local county residents produced an additional $12 million in property tax savings over five years. For further discussion, please see PGE Exhibit 300.
- Virtual Computer Network Servers: Physical servers have been consolidated to reduce the initial hardware costs and the operating costs of physical servers.

[10] The approximated savings is calculated using an 80% operation of Boardman (100% is 8,760 hours per year). The 80% is approximated from 46 days of maintenance scheduled in 2011 and a 10% forced outage. The flat average forward cost of power used is $51 /MWh and PGE owns 65 percent of the plant and output.

Virtual servers reduce data center power and cooling costs in addition to reduction in overall cost per server. The consolidation to virtual servers has reduced the need for 201 additional Windows physical servers down to eight physical hosts. The result is a net capital cost savings of approximately $1.2 million. Please see PGE Exhibit 600 for more information.

C. Efficiency and Cost Effectiveness in Operations

Q. Did PGE also implement changes in the operational day-to-day activities that led to cost efficiencies?

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

Q. In addition to these operational methods has PGE implemented any actions leading to specific operational cost efficiencies?

A. Yes. We have implemented smaller operational efficiencies throughout PGE. The operational efficiencies are geared toward doing our day-to-day work, improving and redesigning business processes, which includes streamlining, eliminating duplication and unnecessary steps, and using technology. Refer to PGE Exhibit 203 for examples.

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

A. The goal of the budget process is to best allocate limited resources to achieve our corporate goals of delivering safe, reliable power and efficient customer service. PGE does this in a continuously changing environment with regard to regulation, the economy, technology, and customer expectations. These all impact how we do our work and the associated costs. As costs increase, we focus on doing our work efficiently to mitigate the effect of cost increases on our customers.

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

A. Our O&M budget process relies on managers to know their areas of responsibility, including how the work is accomplished and the resources required to perform it. With officer guidance, managers develop budgets and must identify variances from the previous year's budget. Proposed budgets are then reviewed by senior managers and officers and adjustments are made as appropriate. Officers review actual results compared to budget on an income statement line-item basis. To the extent that variances are significant, the CEO may direct officers to find offsetting reductions. On a regular basis, analysts and managers monitor actual expenses and revenues, taking corrective action in response to deviations. The budget reports and management and executive review serve as controls during the budget year. Absent justifiable and unforeseen circumstances, spending is within budgeted limits.

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

A. The Capital Review Group, a cross functional group of senior PGE managers, reviews all proposed capital projects (except major construction projects such as Biglow Canyon and AMI). Projects are prioritized and the group recommends to the CEO which ones should proceed. Project approval ensures that plans to commit resources receive thorough scrutiny, appropriate authorization, and adequate follow-up. If the project scope changes significantly after it has been approved, the project is again reviewed.

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

A. PGE's general procurement strategy uses a competitive process led by the Sourcing and Contracts team of specialized buyers. The buyers are familiar with vendors, products, and services as well as the current market conditions. With regard to commonly used items like cable and transformers, PGE negotiates volume pricing and discounts.

For significant purchases, we promote formal bidding. Construction projects, for which there is a defined scope of work and available contractors, are nearly always bid, although the type of the contract may differ. Bids are evaluated based on total ownership cost[11] and awarded to the lowest evaluated bidder. However, cost of the good or service, while important, is not the only factor. For example, fleet purchases, (e.g., hybrid or specialized equipment) may have other factors such as the uniqueness of the required product. In software purchases, factors like maintenance or change-out costs may significantly influence the purchasing strategy. In these cases, users are required to justify single or sole sources for the purchase. In many areas, procurement decisions are a collaborative effort with the department that uses the good or service.

Q. How does PGE reinforce efficiency and cost effectiveness in power purchases and sales?

A. As an energy deficient utility, PGE's key strategy in power purchases and sales is to 1) assure that PGE meets current and forecasted customer energy needs short-term and long-term at the best power cost, and 2) reduce price volatility for customers. The Power Supply group does this in a number of ways through its use of brokers, energy market counterparties and participation in industry groups.

The Power Supply group employs a time-diversification strategy for energy purchases and sales, meaning that PGE generally layers the purchases and sales over the course of multiple weeks, months, and even years. This strategy is used to help PGE take advantage

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

of pricing opportunities for market purchases, and also as a means to reduce customer rate volatility. To achieve the best possible transaction value for this strategy, PGE uses multiple brokerage firms, which are paid a fee only if a transaction is completed. Over-the-counter (OTC) power brokers match power buyers and sellers, much like a real estate broker matches home buyers and sellers.

In contrast to exchange-based clearing brokers, OTC brokers do not act as counterparties, do not take title to power, and do not make financial or physical commitments to provide power. The OTC brokers can be electronic, like the Inter-Continental Exchange (ICE) which is akin to E-Trade, or "voice brokers." Voice brokers use people to perform their brokering services over dedicated phone lines and "squawk boxes" that reach their customers. In either case, the OTC brokers have the infrastructure in place to reach many power trading counterparties at one time, and by utilizing several brokerage firms at once, PGE greatly expands its market coverage in a manner that would otherwise be impossible for PGE to achieve without significant additional staffing.

In markets for "non-standard products," PGE also has direct transactions with energy market counterparties. Non-standard products refer to volumes, terms, and energy shapes that do not fit neatly into the highly commoditized standard on-peak and off-peak fixed price categories handled by brokers. These direct contacts allow PGE to acquire products that better fit customer needs. These products include, but are not limited to, energy exchanges, capacity purchases, merchant transmission and transport management.

Lastly, PGE works diligently in regional regulatory, reliability, and wholesale energy customer forums in an attempt to positively influence policies that impact PGE customers. PGE has been very active in Mid-Columbia Operating and Technical Committees for hydro concerns, with WECC, Western System Power Pool, and the Pacific Northwest Utilities

Conference Committee for topics of reliability, reserves, and wind integration costs, and directly with BPA Transmission to ensure that energy from PGE resources can be wheeled back to PGE's service territory in a cost-effective manner.

Q. Do you have examples of changes in operations that led to efficiencies?

A. Yes. I have included a number of examples in PGE Exhibit 203.

Q. Have you heard concerns about PGE's efficiency and cost effectiveness from investors?

A. Not really. Investors expect us to be efficient and cost effective. Investors, analysts and rating agencies are continuously comparing PGE with other utilities based on broad sets of data and they do not see us as an outlier on our O&M costs. They do see us as an outlier in terms of issues like our power cost adjustment mechanism, and the impact of hydro conditions on power costs,[12] which make it more difficult to predict PGE's cost recovery, corporate performance and shareholder return. Our O&M expenses are not the issue for investors because our costs are in line with other utilities.

[12] PGE's AUT filing includes average hydro conditions to forecast Net Variable Power Costs for the following year. This estimate of average is based on 62 years of historical hydro flows. As regional climate conditions change, this calculation no longer represents a true average for hydro flows. Over the past 16 years (1993 - 2009), the region has only experienced either average, or above average, hydro flow conditions, as measured at The Dalles, four years or 25% of the time.

III. Revised PCAM Structure

Q. Please describe PGE's current Power Cost Adjustment Mechanism (PCAM) structure.

A. The current PCAM, approved by the Commission in UE 180[13] provides for sharing of power cost variances between PGE shareholders and customers based on an asymmetric and dynamic deadband construct, with 90/10 sharing outside of the deadband, and an earnings test with a 100 basis point deadband around the Commission-authorized ROE.

Q. As PGE's Chief Financial Officer, have you heard from investors directly regarding the PCAM mechanism?

A. Yes, the comments that I have received both verbally and through analyst reports suggest the investment community views our PCAM negatively as compared to our peers. The negative view is expressed three ways: 1) PGE's PCAM places too much of the power cost variances, including impacts of hydro conditions, on PGE shareholders; 2) It is complicated and difficult to understand and predict how it will affect PGE's power cost recovery; and 3) It is unlike other utility PCAMs and its results are not easily compared with others[14]. While this could be justified if PGE received higher authorized ROEs as a result, I do not believe the OPUC has granted such premium ROEs.

Q. Do you have any other support of view that PGE's PCAM is structured inappropriately?

A. Yes. We asked Steve Fetter, a former Michigan Commissioner and Chairman, to review PGE's PCAM structure. Mr. Fetter has unique experiences since he has been both a former regulator and has worked in the investment community for Fitch. Mr. Fetter's testimony is provided in PGE Exhibit 1300. I agree with his conclusions that:

[13] Order 07-015

[14] PGE conducted a study of PCAMs across the country. The study demonstrates that PGE's PCAM structure is an outlier relative to others. This study is included in Work Papers.

1) PGE's PCAM structure does not provide PGE with an adequate opportunity to recover our prudently incurred costs.

2) As compared with PCAM structures elsewhere in the country, PGE's PCAM places an unusually large amount of risk on the company and, as a result, puts PGE at a disadvantage compared to our competitors for capital.

3) Our customers will experience higher costs of capital in the long run as a result of our disadvantageous position in capital markets.

Q. What has been PGE's experience with the current PCAM to date?

A. Figure 3 below summarizes the results of the PCAM from 2007 through 2009.

Figure 3

	2007	2008	2009
Total Power Cost Variances	$(29.5) million	$(31.8) million	$22.3 million
Customer portion based on Variance Sharing	$(16.5) million	$(16.1) million	$0
Customer portion after Earnings Test application	$(16.5) million	$0	$0
PGE Shareholder portion after Earnings Test application	$(13.0) million	$(31.8) million	$22.3 million

Q. What does this experience demonstrate?

A. It demonstrates that PGE is subject to significant power cost volatility and a substantial portion of power cost variances remain with PGE shareholders.

Q. How do you propose to revise the PCAM structure?

A. I propose that the deadband be narrowed, made symmetrical, and be fixed in dollar terms rather than expressed as a function of ROE. In addition, I propose a change to remove the 100 basis point deadband construct in the earnings test. Figure 4 below, summarizes the current and proposed PCAM attributes. A copy of the revised Schedule 126, consistent with this proposal, is included in PGE Exhibit 1501.

Figure 4

Feature	Proposed	Current
Deadband – Higher NVPC	$10 million	150 bp of authorized ROE. For 2011, this would equate to $39.9 million.
Deadband – Lower NVPC	$10 million	75 bp of authorized ROE. For 2011, this would equate to $(19.95) million.
Earnings Test - Refunds	Refunds will be made such that PGE's actual regulated ROE is no less than the Commission authorized ROE.	Refunds will be made such that PGE's actual regulated ROE is no less than 100 bp above the Commission authorized ROE.
Earnings Test – Collections	Collections will be allowed such that PGE's actual regulated ROE is no higher than the Commission authorized ROE	Collections will be allowed such that PGE's actual regulated ROE is no higher than 100 bp below the Commission authorized ROE.

Q. Why do you propose these changes?

A. These changes are necessary so that PGE has lower costs of capital over the longer run which translates to lower costs to customers over the longer run. The PGE PCAM structure should be more in line with the structure of mechanisms that apply to our peer utilities. PGE must compete for capital with these peer utilities and a less robust PCAM mechanism coupled with the absence of any compensating increase in the authorized ROE from the Oregon Commission places PGE at a disadvantage in the capital markets. The PCAM structure for our peer utilities and the impact of the PCAM on ROE is discussed further in PGE Exhibit 1200.

Q. How did you determine that $10 million is an appropriate deadband?

A. The majority of our peers have PCAM structures without any deadband at all, and of those that do, we could find only one with a larger deadband than the equivalent of about 100 basis points. However, in recognition that a deadband may provide additional incentives to manage costs, (beyond simple sharing alone), I propose a fixed deadband of $10 million, that is roughly equal to 40 basis points of ROE on PGE's expected 2011 rate base.

Q. Why do you propose to modify the earnings test to remove the 100 basis point deadband?

A. The earnings test deadband effectively acts as a second deadband above and beyond the power cost variance deadband. A PCAM should not provide for over-earning when power costs are lower and under-earning when costs are higher. The authorized ROE provides a reasonable point for limiting collections/refunds under the mechanism.

Q. Why do you propose to make the deadband symmetrical?

A. An asymmetric deadband is inconsistent with the appropriate goal of a PCAM to allow a utility to collect its prudently incurred cost of service as discussed in PGE Exhibit 1300. The original rationale for this element of the structure was that the risk of power cost variances were asymmetrical (higher power costs being more likely than lower power costs). If this is the case, an asymmetrical deadband ensures that prudently incurred costs will never be collected.

Q. The Commission articulated principles of the PCAM in UE 180 that are reflected in the design of PGE's PCAM. Should these principles be revisited?

A. Yes, particularly when viewed in the context of our peer group utilities. The current PCAM, coupled with a failure to grant a compensating increase in the authorized ROE for the additional risk PGE faces creates a disadvantage to the company in raising capital. The appropriate principles for the development of a PCAM are discussed in PGE Exhibit 1300.

IV. Qualifications

Q. Please describe your educational background and experience?

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

List of Exhibits

PGE Exhibit	**Description**
201	Pacific Economics Group Final Report
202	Benchmarking Inventory
203	Operational Efficiencies

BENCHMARKING THE OPERATING PERFORMANCE OF PORTLAND GENERAL ELECTRIC

Pacific Economics Group Research, LLC

BENCHMARKING THE OPERATING PERFORMANCE OF PORTLAND GENERAL ELECTRIC

10 February 2010

Mark Newton Lowry, Ph.D.
President

David Hovde, M.S.
Vice President

Lullit Getachew, Ph.D.
Senior Economist

PACIFIC ECONOMICS GROUP RESEARCH LLC
22 East Mifflin, Suite 302
Madison, Wisconsin USA 53703
608.257.1522   608.257.1540 Fax

TABLE OF CONTENTS

1. INTRODUCTION AND SUMMARY

1.1 Introduction

Portland General Electric ("PGE" or "the Company") is preparing to file for an increase in the base rates that recover the cost of its non-fuel inputs. Benchmarking is useful in assessing the reasonableness of its request. Managers use benchmarking today to gauge how well their companies are doing. Benchmarking also plays a growing role in regulation.

The personnel of Pacific Economics Group ("PEG") Research LLC have extensive experience in utility performance research and incentive regulation, fields with a common foundation in economic statistics. Testimony quality benchmarking studies are a company specialty. We pioneered the use of scientific benchmarking methods in North American regulation. Company president and senior author Mark Newton Lowry has testified on benchmarking in numerous proceedings.

PGE has retained PEG Research to undertake an assessment of its recent operating performance. Separate studies were requested of non fuel operation and maintenance ("O&M") expenses for generation and for distribution, customer care, and administration ("DCA").[1] We have also been asked to benchmark the Company's distribution reliability.

Following a brief summary of the work below, Chapter 2 provides an introduction to benchmarking and discusses our research methodology. Portland General Electric is described in Chapter 3. Our empirical research on DCA expenses is discussed in Chapter 4 and that for power generation expenses in Chapter 5. Chapter 6 provides a discussion of our reliability research. Some technical details of the research are presented in the Appendix.

1.2 Summary of Research

Guided by economic theory, we developed mathematical models of the impact that various quantifiable business conditions have on the DCA and non-fuel generation O&M expenses of electric utilities. The parameters of the models, which measure cost impact, were estimated statistically using historical data on utility operations. Models fitted with

[1] Power transmission expenses were excluded from the study because it is difficult to capture in a benchmarking study the oversized role that the Bonneville Power Administration plays in providing PGE with transmission services.

econometric parameter estimates and the business conditions that PGE faces were used as benchmarks. All estimates of the key model parameters were plausible and highly significant. We believe that this is the best practice approach to utility performance benchmarking given the data that are available in the United States today.

The econometric cost research was based on a sample of good quality data for 105 U.S. power distribution and 54 power generation utilities. The sample period was 1995 to 2008 for DCA and 2001-2007 for generation. The samples are large and varied enough to permit the development of highly credible cost models. The data used in model estimation were drawn from the Federal Energy Regulatory Commissions ("FERC") Form 1 and other respected public sources. The DCA expenses of PGE were found to be about 11% below the benchmarks generated by the econometric model on average from 2006 to 2008. The Company's non-fuel generation expenses were found to be about 5% below the benchmarks on average over the same period.

To benchmark the power reliability performance of PGE we used two metrics: the System Average Interruption Duration Index ("SAIDI") and the System Average Interruption Frequency Index ("SAIFI"). We compared PGE's reliability indices to benchmarks using econometric reliability models developed using standardized and publicly available data from 40 U.S utilities. These models quantified the impact of several business conditions on the reliability metrics. PGE's SAIDI and SAIFI were found to be 67% and 48%, respectively below the benchmarks yielded by our econometric models on average from 2006 to 2008. Statistical tests revealed that these were significantly superior reliability performances.

2. AN INTRODUCTION TO BENCHMARKING

In this section of the report we introduce some important benchmarking concepts. The econometric benchmarking method used in the study is explained. More technical details of our methodology are discussed in the Appendix.

2.1 What is Benchmarking?

The word benchmark originally comes from the field of surveying. The *Oxford English Dictionary* defines a benchmark as

> A surveyors mark, cut in some durable material, as a rock, wall, gate pillar, face of a building, etc. to indicate the starting, closing, ending or any suitable intermediate point in a line of levels for the determination of altitudes over the face of a country.

The term has subsequently been used more generally to indicate something that can be used as a point of comparison in performance appraisals.

A quantitative benchmarking exercise commonly involves one or more gauges of activity. These are sometimes called key performance indicators ("KPIs"). The value of each indicator achieved by an entity under scrutiny is compared to a benchmark value that reflects a performance standard. Given data on the cost of PGE and a certain cost benchmark we might, for instance, measure its cost performance by taking the ratio of the two values:

$$\text{Cost Performance} = \text{Cost}^{PGE}/\text{Cost}^{Benchmark}.$$

Benchmarks are often developed using data on the operations of agents that are involved in the activity under study. Statistical methods are useful in both the calculation of benchmarks and the comparison process. An approach to benchmarking that prominently features statistical methods is called statistical benchmarking.

Various performance standards can be used in benchmarking. These often reflect statistical concepts. One sensible standard is the average performance of the utilities in the sample.

2.2 External Business Conditions

For costs and many other kinds of KPIs, it is widely recognized that differences in the values of the indicators that companies achieve depend partly on differences in performance and partly on differences in the business conditions that they face. In cost research these conditions are sometimes called cost "drivers".[2] The performance of a company depends on the KPI value that it achieves *given the business conditions that it faces*. Benchmarks must therefore reflect local business conditions if they are to embody a chosen performance standard faithfully.

Economic theory is useful in identifying cost drivers and controlling for their influence in benchmarking. We begin by positing that the actual cost incurred by a company is the product of the minimum achievable cost and an efficiency factor.[3] The goal of cost benchmarking is then to accurately estimate the efficiency factor.

Consider now that, under certain reasonable assumptions, cost functions exist that relate the minimum cost of an enterprise to business conditions in its service territory. When the focus of benchmarking is a subset of the entire series of inputs, cost theory shows that the minimum cost depends on the prices of the included inputs, output quantities, and on the amounts of other inputs that the company uses. This means that a fair appraisal of the efficiency with which a utility uses O&M inputs depends on the quantities of *capital* inputs that it owns.

Cost theory allows for the existence of *multiple* output variables in a cost function. This is important because it is often impossible to accurately measure the workload of a utility using only one output variable. The cost of power distribution may depend, for example, on the volume of power delivered as well as the number of customers served. It is also noteworthy that theory allows for the possibility that numerous business conditions other than input prices and output quantities can affect the minimum cost of service.

[2] Business conditions that influence reliability indicators may, similarly, be called reliability drivers.
[3] Minimum achievable cost is a hypothetical notion and cannot be precisely calculated for specific utilities.

2.3 Econometric Benchmarking

2.3.1 Basic Assumptions

Relationships between the KPIs of utilities and the business conditions that they face can be estimated using statistics. A branch of statistics called econometrics has developed procedures for estimating the parameters of economic models using historical data.[4] The parameters of a cost function, for example, can be estimated using historical data on the costs incurred by a group of utilities and the business conditions that they faced. The sample used in model estimation can be a time series consisting of data over several years for a single company, a cross section consisting of one observation for each of several companies, or a "panel" data set that pools time series data for several companies.

Econometric research involves certain critical assumptions. The most important assumption, perhaps, is that the values of some economic variables (called dependent or left-hand side variables) are functions of certain other variables (called explanatory or right hand side variables) and error terms. In a cost model, cost is the dependent variable and the cost drivers are the explanatory variables. The explanatory variables are generally assumed to be independent in the sense that their values are not influenced by the values of dependent variables.

The error term in an econometric model for a KPI is the difference between the actual value of the indicator and the value predicted by the model. It reflects imperfections in the development of the model. The imperfections may include the mismeasurement of external business conditions, the exclusion from the model of relevant business conditions, and the failure of the model to capture the true form of the underlying functional relationship. Error terms are, in effect, a formal acknowledgement of the fact that the model is unlikely to provide a full explanation of the variation in the values of the KPIs for sampled utilities.

It is customary to assume that error terms are random variables with probability distributions that are determined by additional parameters, such as mean and variance, that can be estimated. This practice has several uses in econometric benchmarking. For example, tests can be constructed for the hypothesis that the parameter for a business

[4] The act of estimating model parameters is sometimes called regression analysis.

condition variable under consideration for inclusion in a KPI model equals zero. A variable can be deemed a statistically significant cost driver if this hypothesis is rejected at a high level of confidence. In a benchmarking study used in utility regulation it is sensible to exclude from the model candidate business condition variables that do not have statistically significant parameter estimates, as well as those with implausible parameter estimates.

2.3.2 KPI Predictions and Performance Appraisals

A cost function fitted with econometric parameter estimates may be called an econometric cost model. A function for a reliability indicator such as SAIDI fitted with econometric parameter estimates may be called an econometric reliability model. We can use such models to predict a company's KPI values given local values for the business condition variables. These predictions are econometric benchmarks. KPI performance is measured in year *t* by comparing a company's KPI value in that year to the value projected for that year by the econometric model. [5]

2.3.3 Testing Efficiency Hypotheses

In econometric benchmarking, as in other approaches to benchmarking, there is naturally uncertainty about the accuracy of the "best guess" benchmark. One advantage of the econometric approach to benchmarking is that we can use econometric theory to identify a range of benchmark values, called a confidence interval, that encompasses the true benchmark value at a certain (*e.g.* 90%) confidence level. Confidence intervals developed from econometric results do more than provide us with indications of the accuracy of a benchmarking exercise. In particular, they permit us to test hypotheses regarding cost efficiency. Suppose, for example, that we use a sample average efficiency standard and compute the confidence interval for the benchmark that corresponds to the 90% confidence

---

[5] Suppose, for example, that we wish to benchmark the distribution expenses of a hypothetical electric utility called Western Power. We might then predict the cost of Western in period *t* using the following model.

$$\hat{C}_{Western,t} = \hat{a}_0 + \hat{a}_1 \cdot N_{Western,t} + \hat{a}_2 \cdot W_{Western,t}.$$

Here $\hat{C}_{Western,t}$ denotes the predicted cost of the company, $N_{Western,t}$ is the number of customers it serves, and $W_{Western,t}$ measures its wage rate. The $\hat{a}_0$, $\hat{a}_1$, and $\hat{a}_2$ terms are parameter estimates. Performance might then be measured using a formula such as

$$Performance = \left(C_{Western,t} \middle/ \hat{C}_{Western,t} \right).$$

level. It is then possible to test the hypothesis that the company has attained the benchmark standard of efficiency. If, for example, the company's actual cost exceeds the best guess benchmark generated by the model but nonetheless lies within the confidence interval this hypothesis cannot be rejected. In other words, the company is not a *significantly* inferior cost performer. Suppose, alternatively, that the company's cost is below the cost predicted by the model by enough to be outside the confidence interval. We may then conclude that it is a *significantly superior* cost performer.

An important advantage of efficiency hypothesis tests is that they take into account the accuracy of the benchmarking exercise. As we have tried to emphasize, there is uncertainty involved in the prediction of benchmarks. These uncertainties are properly reflected in the confidence interval that surrounds the point estimate (best single guess) of the benchmark value. The confidence interval will be greater the greater is the uncertainty regarding the true benchmark value. If uncertainty is great, our ability to draw conclusions about operating efficiency is hampered.

2.3.4 Functional Form

Econometric research requires the choice of a form for the functional relationship between a KPI and the business conditions that influence it. It is generally desirable to permit some flexibility in the form that is specified since the true form of the relationship between a KPI and the corresponding business conditions is usually unknown. We attempt to accomplish this by adding some quadratic terms (*e.g* labor price x labor price) and interaction terms (*e.g.* labor price x delivery volume) to our models. The other terms in the model (*i.e.* those that are not quadratic or interaction terms) are called "first order" terms.

2.3.5 Multiple Equation Cost Models

Economic cost benchmarking is sometimes undertaken with multiple equation cost models. For example, non-fuel O&M expenses might be benchmarked with a model that consists of an O&M cost function and a *cost share* equation for labor that addresses the share of the expenses that is spent on labor.

A rigorous multiple equation approach to cost modeling that includes one or more share equations is generally preferable to the single equation approach. The chief advantage results from the fact that economic theory suggests that the parameters of the cost function and share equations are linked. More data can thus be used in the estimation of cost model parameters. This increases the prospects for developing a cost benchmarking model that accurately reflects the effects of external business conditions. We have followed this approach in both cost studies described in this report.

3. An Introduction to Portland General Electric

PGE is a vertically integrated U.S. electric utility based in Portland, Oregon. Metropolitan Portland is the heart of its service territory. Service is provided, additionally, to numerous smaller towns outside the metro area that are located in the northern Willamette Valley. The company has about 800,000 retail customers. Residential and commercial customers account for the great bulk of retail demand.

The company has a remarkably diverse power supply mix. In 2008, self-generation accounted for only 66% of retail sales. Power is purchased from a diverse mix of vendors that consist primarily of publicly held hydro generators in the Pacific Northwest and a number of independent power producers.

About 43% of self-generation capacity is coal-fired. This includes the Boardman plant, a 1980 vintage facility located on the Columbia River near Umatilla, and the Colstrip plant, located in eastern Montana, which PGE co-owns with several other companies. About 41% of generated power is obtained from other fossil-fuel plants. These consist chiefly of gas-fired combined cycle units. The remaining 16% of PGE's generation output is obtained from hydroelectric facilities, which are located to the south and east of Portland in the Cascade Mountains. The largest of these is the Pelton-Round Butte facility near Madras on the eastern slope.

The Company owns and operates almost 1,600 miles of transmission line. The need for such lines is reduced by several circumstances. PGE has a compact service territory and most of the Company's own power generation is located fairly close to Portland. A substantial share of all purchased power, as well as power from the distant Colstrip plant, is delivered to the Company over transmission lines owned by the Bonneville Power Administration.

4. POWER DISTRIBUTION RESEARCH

4.1 Data

The primary sources of the cost and quantity data used in our empirical research for PGE were the Federal Energy Regulatory Commission ("FERC") Form 1 and Form EIA 861 ("Annual Electric Utility Report"). Our data for both of these sources were gathered by SNL, a reputable commercial vendor. Major investor-owned electric utilities in the United States are required by law to file both forms annually. Data reported on the FERC Form 1 must conform to the FERC's Uniform System of Accounts. Details of these accounts can be found in Title 18 of the Code of Federal Regulations.

Data were considered for inclusion in the sample from all major U.S. investor-owned electric utilities that filed the FERC Form 1 in 2008 and had substantial involvement in power distribution and customer care.[6] To be included in the study the data were required, additionally, to be plausible and not unduly burdensome to process. Data from 105 companies were used in the power distribution research. These companies are listed in Table 1. The sample period was 1995-2008. The resultant data set has 1,446 observations.[7] This sample is large and varied enough to permit econometric identification of numerous O&M cost drivers and reasonably accurate estimation of their cost impact.

Other sources of data were also accessed in the research. Some of these sources are used to measure input prices, and included the Bureau of Labor Statistics ("BLS") of the U.S. Department of Labor for labor prices and Global Insight for electric utility material and service ("M&S") prices. Data on weather related variables and the number of gas customers served were obtained from the National Climatic Data Center and gas distributor filings to state Commissions, respectively.

4.2 Definition of Variables

4.2.1 Cost

Cost figures play a key role in our research for PGE. The expenses used in the DCA benchmarking work are reported O&M expenses for distribution, customer accounts,

[6] We excluded from the sample some utilities that were primarily engaged in power generation or transmission.
[7] Some observations for companies with data included in the sample were excluded due to data problems.

Table 1

SAMPLE OF UTILITIES IN THE DCA COST RESEARCH

Alabama Power
AmerenUE
Appalachian Power
Arizona Public Service
Atlantic City Electric
Avista
Baltimore Gas and Electric
Bangor Hydro-Electric
Black Hills Power
Carolina Power & Light
Central Hudson Gas & Electric
Central Illinois Light
Central Illinois Public Service
Central Maine Power
Central Vermont Public Service
Cleco Power
Cleveland Electric Illuminating
Columbus Southern Power
Commonwealth Edison
Connecticut Light and Power
Consolidated Edison
Consumers Energy
Dayton Power and Light
Delmarva Power & Light
Detroit Edison
Duke Energy Carolinas
Duke Energy Indiana
Duke Energy Ohio
Edison Sault Electric
El Paso Electric
Empire District Electric
Entergy Arkansas
Entergy Mississippi
Fitchburg Gas and Electric Light
Florida Power & Light
Florida Power
Georgia Power
Green Mountain Power
Gulf Power
Idaho Power
Illinois Power
Indiana Michigan Power
Indianapolis Power & Light
Kansas City Power & Light
Kansas Gas and Electric
Kentucky Power
Kentucky Utilities
Kingsport Power
Lockhart Power
Louisville Gas and Electric
Madison Gas and Electric
Maine Public Service
Massachusetts Electric
Metropolitan Edison
MidAmerican Energy
Minnesota Power
Monongahela Power
MDU Resources Group
Narragansett Electric
Nevada Power
Northern Indiana Public Service
Northern States Power - MN
Northern States Power - WI
Ohio Edison
Ohio Power
Oklahoma Gas and Electric
Orange and Rockland Utilities
Otter Tail
Pacific Gas and Electric
PacifiCorp
PECO Energy
Pennsylvania Electric
Pennsylvania Power
Pennsylvania Power & Light
Portland General Electric
Potomac Edison
Potomac Electric Power
Public Service Company of Colorado
Public Service Company of New Hampshire
Public Service Company of New Mexico
Public Service Company of Oklahoma
Public Service Electric and Gas
Puget Sound Energy
Rochester Gas & Electric
San Diego Gas & Electric
Sierra Pacific Power
South Carolina Electric & Gas
Southern California Edison
Southern Indiana Gas and Electric
Southwestern Electric Power
Southwestern Public Service
Superior Water, Light and Power
Tampa Electric
Toledo Edison
Tucson Electric Power
United Illuminating
Upper Peninsula Power
Virginia Electric Power
West Penn Power
Western Massachusetts Electric
Westar Energy
Wheeling Power
Wisconsin Electric Power
Wisconsin Power & Light
Wisconsin Public Service

105 sampled utilities

customer service and information, sales, and administration less franchise fees and expenses for pensions and benefits. We routinely exclude pension and benefit expenses from our cost benchmarking work on the grounds that they are volatile, vary with accounting practices, and are to a considerable degree beyond the control of utility management.

4.2.2 Output Measures

Two output measures are used in the DCA cost model. One is the annual average number of customers served. The other is the megawatt hours of residential and commercial retail deliveries.[8]

4.2.3 Input Prices

Cost theory also suggests that the prices paid for production inputs are relevant business condition variables. In this model, we have specified price indexes for labor and M&S inputs.[9] We expect cost to be higher the higher are the values of both indexes.

The labor price index used in this study is constructed by PEG Research personnel using BLS data. Occupational Employment Statistics ("OES") data for 2008 are used to construct wage rate comparisons for each utility's service territory. An average wage comparison is calculated using cost share weights that correspond to the electric utility industry for the U.S. as a whole. Values for other years are calculated by adjusting the index level in the focus year for changes in regionalized BLS indexes of employment cost trends in the utility sector.

Prices for material and service ("M&S") O&M inputs are assumed to have a 25% local labor content and therefore tend to be a little higher in regions with higher labor prices. They are escalated by a summary M&S input price index constructed by PEG Research from detailed Global Insight electric utility M&S indexes.

4.2.4 Other Business Conditions

Seven other business condition variables are included in the DCA cost model. These variables measure conditions that affect the cost of providing DCA services. One of these variables measures the extent of system overheading. System overheading involves higher

[8] Industrial and other retail deliveries are excluded because they tend to have considerably less cost impact per MWh.
[9] Cost is divided by the M&S input price so that this variable does not appear explicitly in the model.

O&M expenses over the years because lines are more exposed to the challenges posed by local weather (*e.g.* high winds and ice storms), flora, and fauna[10]. The variable used to capture the extent of overheading is the share of overhead distribution plant in the total gross value of overhead and underground plant. The FERC Form 1 is the source of the plant value data.

A second additional business condition variable is a measure of the demand side management ("DSM") work being done by each utility. Due to a lack of explicit itemization of DSM expenses on the FERC Form 1, these expenses are difficult to remove from the costs subject to benchmarking. A control variable is therefore needed and we use for this purpose the share of customer service and information ("CS&I") expenses in the total distribution, customer account, and CS&I expenses on FERC Form 1. This approach makes sense because DSM expenses are usually reported as a CS&I expense and loom large in these expenses when DSM programs are large. Given this, we would expect that the higher the value of the variable the higher DCA cost would be. We expect the corresponding parameter estimate to have a positive sign.

The third added business condition variable is the number of customers for which a utility provides gas service. Simultaneous provision of delivery and customer care services to gas and electric customers involves opportunities to share inputs that economists call economies of scope. We therefore expect a utility's reported electric O&M expenses to be lower the higher is the number of gas customers served. The parameter estimate should have a negative sign.

The average heating degree days in each utility's service territory is the fourth additional business condition variable in the model. This variable captures the cost associated with operating under severe winter weather conditions. We expect the corresponding parameter estimate to be positive.

The company's net generation volume is the fifth business condition variable. This variable was included to capture the extra administrative costs of running a generation operation. We expect the parameter estimate for this variable to have a positive sign.

A sixth added variable is the average precipitation in the service territory. This serves as a proxy for forestation, which raises distributor O&M cost due to tree trimming

[10] Maintenance of underground distribution facilities occurs less frequently but can be quite costly.

and maintenance activities. Thus, we expect the parameter estimate corresponding to this variable to be positive.

The econometric model also contains a trend variable. This permits predicted cost to shift over time for reasons other than changes in the specified business conditions. The trend variable captures the net effect on cost of diverse conditions, such as technological change, that are otherwise excluded from the model. Parameters for such variables typically have a negative sign in statistical cost research.

4.3 Parameter Estimates

Estimation results for the cost model are reported in Table 2. In this and the other three tables that present econometric results, we shade results for first order terms for reader convenience. These tables also report the values of the t-ratios that correspond to each parameter estimate. A parameter estimate is deemed statistically significant if the hypothesis that the true parameter value equals zero is rejected. This statistical test requires the selection of a critical value for the t ratio. In this study, we employed a critical value that is appropriate for a 90% confidence level given a large sample. The value of the t-ratio corresponding to this confidence level is about 1.6. The t-ratios are used in model specification. All first order terms were required to have statistically significant and sensibly-signed parameter estimates.

Table 2 and the other tables of econometric results also report p values. These are alternative indicators of the statistical significance of parameter estimates. A parameter estimate that is significant at no more than a 90% confidence level has a p value of 0.10.

Examining the results in Table 2, it can be seen that all of the parameter estimates for first order terms are statistically significant and plausible as to sign and magnitude. At the sample mean, cost was found to be higher the higher were the values of the two scale-related variables. A 1% increase in the number of customers served is estimated to raise O&M expenses by 0.82%. A 1% hike in the residential and commercial delivered volume is estimated to raise cost by 0.13% in the long run. Thus, the number of customers served is

Table 2

Econometric Model of Distribution, Customer Care, and Administrative O&M Expenses

VARIABLE KEY

WL = Labor Price
N = Number of Customers
VRC = Residential & Commercial Delivery Volume
DSM = Share of CS&I in Distribution and Customer Care O&M
POH = Percent of Distribution Plant Overhead
NG = Number of Gas Customers
G = Net Generation
HDD = Average Heating Degree Days
P = Average Precipitation
Trend = Time Trend

COST DRIVER	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
WL	0.360	108.99	0.000
WLWL	0.093	2.41	0.016
WLN	-0.009	-0.69	0.489
WLVRC	-0.012	-1.03	0.305
N	0.817	31.06	0.000
NN	0.381	2.88	0.004
NVRC	-0.387	-3.12	0.002
VRC	0.128	4.80	0.000
VRCVRC	0.377	3.17	0.002

COST DRIVER	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
DSM	0.028	6.742	0.000
POH	0.144	7.732	0.000
NG	-0.003	-2.609	0.009
G	0.059	7.152	0.000
HDD	0.009	10.075	0.000
P	0.019	1.848	0.065
Trend	-0.015	-13.893	0.000
Constant	12.300	918.586	0.000
System Rbar-Squared	0.969		
Sample Period	1995-2008		
Number of Observatio	1446		

the chief output related driver of DCA expenses. Cost was also higher the higher was the labor price.

The parameter estimates for the additional business condition variables were also sensible. DCA O&M expenses are

- higher the higher is the apparent amount of DSM work undertaken;
- higher the greater is the extent of distribution system overheading;
- lower the larger is the number of gas customers served;
- higher the greater is the winter weather severity;
- higher the more generation work a utility undertakes; and
- higher the greater is the amount of precipitation.

The estimate of the trend variable parameter suggests a 1.5% annual downward shift in cost for reasons other than the trends in the included business condition variables.

The table also reports the system-R^2 statistic for the model. This is a widely used measure of the ability of the model to explain variation in the sampled costs of distributors. Its value is about 0.97, suggesting that the explanatory power of the model was high.

4.4 Business Conditions of PGE

Table 3 compares the average values of the business conditions that PGE faced over the 2006-2008 period to the average values for the full DCA cost sample. It can be seen that the company's DCA O&M expenses were only 0.91 times the sample mean. The number of customers served was, meanwhile, 0.96 times the mean, while residential and commercial deliveries were 0.95 times the mean and the net generation volume was 0.67 times the mean. Regarding input prices, the table shows that the labor prices faced by PGE were about 1.12 times the sample mean and the M&S price index was 1.03 times the mean.

As for the other business condition variables, DSM programs are administered by an independent agency in Oregon, so the share of CS&I was only 0.59 times the mean. The percentage of plant that is overhead was 0.89 times the mean. This is a reflection of the company's substantially urbanized service territory. There are no gas customers to provide opportunities for scope economies. Average precipitation was 0.98 times the mean, whereas the average heating degree days was 0.84 times the mean.

Table 3

Comparison of PGE's Distribution, Customer Care and A&G Business Conditions To Full Sample Norms

Business Condition	Units	Mean Values 2006-2008		PGE Mean/Sample Mean
		PGE	Full Sample	
Distribution, Customer Care and Administrative O&M Cost	Dollars ('000)	210,311	230,404	0.91
Retail Customers	Count	800,324	837,134	0.96
Residential and Commercial Retail Deliveries	MWh	15,200,311	15,987,694	0.95
Net Generation	MWh	9,757,415	14,636,447	0.67
Labor Price	Index Number	0.938	0.840	1.12
Other O&M Input Price	Index Number	1.239	1.205	1.03
Percent Customer Service and Information Expenses	Percent	0.071	0.120	0.59
Percent of Distribution Plant that is Overhead	Percent	0.564	0.632	0.89
Gas Customers	Count	0	183,721	0.00
Average Precipitation	Inches	35.889	36.704	0.98
Heating Degree Days	Degree Days	4,239	5,036	0.84

4.5 Benchmarking Results

Table 4 presents the results of our econometric appraisal of PGE's average DCA O&M expenses for the 2006-2008 period. The company's cost was about 11% below the model's prediction on average. However, we cannot reject the hypothesis, at the 90% confidence level, that the company was an average DCA cost performer over this period.

Table 4

Comparison of Actual and Predicted DCA Expenses for PGE

Year	Difference (%)
2006	-15.7%
2007	-10.9%
2008	-7.2%
2006-2008 Average	-11.2%

5. POWER GENERATION RESEARCH

5.1 Data

The primary source of the cost and output data used in our research on power generation cost is the FERC Form 1. Other sources of data were also accessed in the power generation research. Data on generation capacity originated in Form EIA – 860 ("Annual Electric Generator Report") and a predecessor data source, Form EIA – 767 ("Annual Steam Electric Plant Operation and Design Report"). We once again rely on SNL compilations. The input price data were obtained from the same sources mentioned in the power distribution section.

Data from 54 companies were used in the power generation research. The sample is smaller than that used in the DCA cost research because many U.S. utilities that provide distribution services have restructured and no longer provide generation services. The companies included in the sample are listed in Table 5. The sample period for model estimation was 2001-2007.[11] The resultant data set has 374 observations.[12] This sample is large and varied enough to permit econometric identification of several generation cost drivers and reasonably accurate estimation of their likely cost impact.

5.2 Definition of Variables

5.2.1 Cost and Output Measures

The generation cost addressed in our study is total power production O&M expenses less fuel and purchased power expenses. In addition to Purchased Power expenses as reported on the FERC Form 1, we also exclude the Other Expenses category of Other Power Supply Expenses. We believe that large and volatile costs that are often commodity-related are sometimes reported in this category. One output measure is used in the generation O&M cost model: the total annual megawatt hours of net generation.

[11] We have less confidence in some of the SNL capacity data before 2001. The requisite capacity data for 2008 are not yet available for all sampled companies.
[12] Some observations for companies in the sample were excluded due to data problems.

Table 5

SAMPLE OF UTILITIES IN GENERATION COST RESEARCH

Alabama Power	MidAmerican Energy
AmerenUE	Minnesota Power
Appalachian Power	Mississippi Power
Arizona Public Service	Montana Dakota Utilities
Avista	Nevada Power
Black Hills Power	Northern Indiana Public Service
Carolina Power & Light	Northern States Power - MN
Cleco Power	Ohio Power
Columbus Southern Power	Oklahoma Gas and Electric
Consumers Energy	Otter Tail Corporation
Dayton Power and Light	PacifiCorp
Detroit Edison	Portland General Electric
Duke Energy Carolinas	Public Service Company of Colorado
Empire District Electric	Public Service Company of New Hampshire
Entergy Mississippi	Public Service Company of New Mexico
Florida Power & Light	Public Service Company of Oklahoma
Florida Power Corporation	Puget Sound Energy
Georgia Power	Sierra Pacific Power
Gulf Power	South Carolina Electric & Gas
Idaho Power	Southern Indiana Gas and Electric
Indiana Michigan Power	Southwestern Electric Power
Indianapolis Power & Light	Southwestern Public Service
Kansas City Power & Light	Tampa Electric
Kentucky Power	Virginia Electric and Power
Kentucky Utilities	Westar Energy (KPL)
Louisville Gas and Electric	Wisconsin Power and Light
Madison Gas and Electric	Wisconsin Public Service

54 sampled utilities

5.2.2 Input Prices

As discussed in Chapter 4, cost theory suggests that the prices paid for production inputs are relevant business condition variables. We include price indexes for two kinds of inputs in the model. The labor price index is the same as that discussed in Chapter 4. The M&S input price index was calculated using data on prices of generation M&S inputs from Global Insight.[13] Like its DCA counterpart, we assume a 25% local labor content for this index so that its value is a little higher in areas of higher salaries and wages.

5.2.3 Other Business Conditions

Five other business condition variables are included in the generation cost model. One is the total generation capacity. Capacity is an important supplemental cost driver because the non-fuel O&M expenses associated with it can be substantial even when it is idle. Data on capacity are processed from EIA 860 data on individual power plants. Our research team aggregated the nameplate capacity of each sampled utility's power plants to arrive at a total capacity figure. We expect that O&M expenses will be higher the higher is the amount of generation capacity. The parameter estimate should therefore have a positive sign.

Two other business condition variables included in the model are the shares of generating capacity owned by each company that are coal-fired and nuclear-fueled. These variables are designed to capture any tendency for O&M expenses to vary with the kind of generating plant that companies own. We expect the parameter estimates corresponding to both variables to have positive signs.

The fourth business condition variable in the model is the percentage of capacity that is scrubbed for sulfur. Cost should be higher the higher is this share. We therefore expect the corresponding parameter estimate to be positive. The econometric model also contains a trend variable. We have noted that the parameters for such variables typically have a negative sign in statistical cost research.

[13] Cost is divided by the generation M&S price so that it does not appear as a right hand side variable in the model.

5.3 Parameter Estimates

Estimation results for the cost model are reported in Table 6. Examining the results, it can be seen that all of the model parameter estimates for first order terms are statistically significant and plausible as to sign and magnitude. At sample mean values of the business condition variables, a 1% hike in the generation volume was estimated to raise cost 0.36%. A 1% increase in generation capacity was estimated to raise cost 0.48%. Here are the results for the other business condition variables.

- Cost was higher the greater was the labor price.
- Cost was higher the greater were the percentages of capacity that were coal-fired or nuclear.
- Cost was also higher the greater was the percentage of capacity that was scrubbed for SO2.
- The estimate of the trend variable parameter suggests a 1.1% annual increase in cost over time for reasons other than the trends in the business condition variables.

The table also reports the system R^2 statistic for the model. This is a widely used measure of the ability of the model to explain variation in the sampled costs of distributors. Its value was about 0.95, suggesting that the explanatory power of the model was high.

5.4 Business Conditions of PGE

Table 7 compares the average values of the generation business conditions that PGE faced from 2005 to 2007 to the average values for the sample. It can be seen that the company's generation O&M expenses were only 0.31 times the sample mean. The net generation volume was 0.34 times the mean, while the generation capacity was 0.40 times the mean. The table also shows that the labor price faced by PGE was about 1.15 times the sample mean.[14]

Turning to the additional business conditions, PGE had no nuclear capacity. The share of its generation capacity that was coal-fired capacity was only 0.61 times the mean. The share of capacity that was scrubbed for sulfur was only 0.71 times the mean.

---

[14] This comparison differs from that in the DCA sample because that sample includes a number of utilities in California and the northeast and north central U.S.

Table 6

Econometric Model of Non-Fuel Generation O&M Expenses

VARIABLE KEY

WL = Labor Price
YG = Net Generation Volume
KG = Total Generation Capacity
PCN = % of Capacity Nuclear
PCC = % of Capacity Coal
PCS = % of Capacity that is Scrubbed
Trend = Time Trend

COST DRIVER	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
WL	0.370	76.73	0.000
WLWL	0.091	1.54	0.125
WLYG	-0.014	-0.86	0.389
WLKG	0.044	2.63	0.009
YG	0.360	7.50	0.000
YGYG	-0.253	-1.72	0.086
YGKG	0.262	1.69	0.092
KG	0.477	9.68	0.000
KGKG	-0.241	-1.40	0.162

COST DRIVER	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
PCN	0.187	24.35	0.000
PCC	0.197	8.44	0.000
PCS	0.019	2.14	0.033
Trend	0.011	3.77	0.000
Constant	11.053	267.39	0.000

System Rbar-Squared	0.946
Sample Period	2001-2007
Number of Observations	374

Table 7

Comparison of PGE's Generation Business Conditions To Full Sample Norms

Business Condition	Units	Mean Values 2005-2007 PGE	Mean Values 2005-2007 Full Sample	PGE Mean/Sample Mean
Generation O&M Cost	Dollars ('000)	56,114	178,362	0.31
Net Generation	MWh	8,477,820	24,634,374	0.34
Total Capacity	MW	2,247	5,551	0.40
Labor Price	Index	0.908	0.790	1.15
Other O&M Input Price	Index	1.495	1.441	1.04
Percent Capacity Nuclear	Percent	0	0.058	0.00
Percent Capacity Coal	Percent	0.325	0.533	0.61
Percent of Total Capacity that is Scrubbed	Percent	0.141	0.200	0.71

5.5 Benchmarking Results

Table 8 presents the results of our econometric appraisal of PGE's generation O&M expenses for the 2006-2008 period. The Company's expenses were found to be about 5% below the model's projection on average. We cannot, at a 90% confidence level, reject the hypothesis that the company was an average cost performer.

Table 8

Comparison of Actual and Predicted Generation Expenses for PGE

Year	Difference (%)
2006	0.7%
2007	-10.0%
2008	-5.9%
2006-2008 Average	-5.1%

6. Reliability Research

We discuss our benchmarking study of the reliability of power distribution service in this section. We start by looking at the measures of distribution reliability followed by the data used in the study. We then present our benchmarking models used to assess PGE's performance.

6.1 Definitions

There are many dimensions of service quality in power distribution. Our focus here is on reliability of power delivery to electric end-users as measured by service continuity and, in case of disruption, rapid restoration of service. Continuous access to electric power is essential to the functioning of modern homes and businesses. The essential nature of power demand makes interruptions in power delivery costly to customers. Power distribution utilities are therefore expected to design and operate distribution networks to assure reliable deliveries. Even well-run delivery systems are, however, subject to disruption from accidents and weather conditions. When disruptions occur, distribution companies are expected to restore service promptly.

The specific indicators that utilities use to gauge reliability vary somewhat from company to company, but there are broad similarities among the types of performance indicators used for this purpose. These metrics gauge mostly the frequency and duration of power interruptions. The two most typical measures used in utility regulation are:

- SAIDI, the number of minutes of sustained power interruptions that is experienced annually by an average customer on the system
- SAIFI, the number of sustained interruptions that is experienced annually by an average customer on the system

Public utility commissions in some jurisdictions mandate reliability standards based on these indices. The definition of "sustained" outages and events that can be excluded from index calculations, called major event days ("MEDs"), vary. In order to ensure comparability of SAIDI and SAIFI definitions used in our study, we collected and used only indices that reflect standards set up by the Institute of Electrical and Electronic Engineers ("IEEE"). In its "Guide for Electric Distribution Reliability Indices," standard number P1366, the IEEE sets up definitions of sustained outages and MEDs. Sustained outages are those that last at least five minutes and MEDs are based on what it calls the beta method. This method sets up threshold values, only above which outages are recorded, based on log averages and standard deviations of daily outage data for the past five years for each utility. Essentially, an MED is based on the experience of each utility standardized in the same way, and permits the smoothing of reliability data that can be affected by extraordinary and severe weather conditions.

6.2 Data

There are two primary sources for the IEEE standard based reliability indices used in this study. The first is public utility commissions that monitor reliability as part of their regulatory activities and make information available either on their website or upon request. The second main source of these data is utilities that for other reasons collect reliability information and calculate indices using the IEEE definitions. We were able to collect data from 40 major electric utilities. The list of these utilities is given in Table 9. The sample is large and varied enough to permit the identification of several reliability drivers. These utilities had IEEE based reliability data for differing years, the most comprehensive being the years 1998-2008 while the most typical was the years 2003-2008. Ultimately, the dataset used to benchmark reliability performance had 248 observations. The sources for the other data used in our reliability benchmarking research are the same ones detailed in the DCA cost benchmarking section.

6.3 Reliability Benchmarking Models

We developed reliability benchmarking models for both SAIDI and SAIFI. The SAIDI model explains system average outage duration using customer density (as measured by the number of customers per distribution line mile), percent plant overhead, forestation, precipitation, heating degree days, and a trend variable. The SAIFI model includes all of the above variables, except plant overhead, and uses cooling degree days instead of heating

Table 9

SAMPLE OF UTILITIES USED IN RELIABILITY RESEARCH

Avista
Baltimore Gas & Electric
Bangor Hydro-Electric
Central Maine Power
Cincinnati Gas & Electric
Cleveland Electric Illuminating
Columbus Southern Power
Commonwealth Edison
Dayton Power & Light
Duquesne Light
Georgia Power
Indianapolis Power & Light
Kansas City Power & Light
Kentucky Power
Kentucky Utilities
Louisville Gas and Electric
Maine Public Service
Metropolitan Edison
Minnesota Power
Northern Indiana Public Service
Northern States Power - Minnesota
Ohio Edison
Ohio Power
Oklahoma Gas and Electric
Otter Tail Power
Pacific Gas and Electric
Pennsylvania Electric
Pennsylvania Power
Portland General Electric
Potomac Electric Power
PSI Energy Inc
Public Service Company of Colorado
Public Service Company of New Mexico
Public Service Company of Oklahoma
Puget Sound Energy
Southern California Edison
Southern Indiana Gas and Electric
Toledo Edison
Union Light Heat & Power
West Penn Power

40 sampled utilities

degree days as explanatory variables. In addition, a quadratic (*i.e.* “squared”) term of the number of customers is featured in both models.[15]

The econometric results for the SAIDI model are presented in Table 10 and those for the SAIFI in Table 11. Inspecting the results in Table 10, it can be seen that the higher the density the shorter was the SAIDI, while overhead plant, forestation, and precipitation increased outage duration. We also note a 0.2% annual increase in SAIDI over the sample period for reasons other than trends in the included business condition variables. We can observe similar estimates in the SAIFI model. Inspecting the results in Table 11 we find that SAIFI was lower with greater customer density, but higher with more forestation, precipitation, and cooling degree days, which is a proxy for the severity of summer heat. The parameter estimate of the trend term in this model indicates a 1.0% annual decline in outage frequency. In both models, the parameter estimates for most of the quadratic terms are significant, suggesting the desirability of flexible functional forms for reliability modeling.

Table 12 presents a comparison of the average values of SAIDI, SAIFI and all right hand side variables used in the models for the 2006 – 2008 period. The SAIDI and SAIFI values experienced by PGE were 49% and 58%, respectively, of the sample means. In addition, compared to the sample average over the same period PGE

- had 19% more customer density;
- had 10% less overhead plant;
- had 57% more forestation;
- had 58% less cooling degree days;
- had 4% less precipitation; and
- served 14% fewer customers.

6.4 Benchmarking Results

Tables 13 and 14 present the results of our econometric appraisal of PGE’s SAIDI and SAIFI, respectively, for the 2006-2008 period. PGE’s SAIDI value was 67% below its

---

[15] Recall that the SAIDI and SAIFI metrics already include the number of customers served in the denominator.

Table 10

Econometric Model of SAIDI

VARIABLE KEY

NMD Customers per Distribution Line Mile
POH % Distribution Plant Overhead
PF % of Forestation
P Average Precipitation
N Number of Customers

RELIABILITY DRIVER	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
NMD	-0.255	-5.003	0.000
NMDNMD	-0.368	-3.057	0.002
POH	0.485	6.362	0.000
POHPOH	1.019	7.034	0.000

RELIABILITY DRIVER	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
PF	0.222	7.388	0.000
PFPF	0.037	1.679	0.094
P	0.192	3.969	0.000
PP	-0.108	-2.039	0.043
NN	-0.031	-3.569	0.000
Trend	0.002	0.337	0.737
Constant	4.866	88.989	0.000

Sample Period	Varies, typically 2003-2008
Number of Observations	248
Rbar-Squared	0.352

Table 11

Econometric Model of SAIFI

VARIABLE KEY

NMD	Customers per Distribution Line Mile
PF	% of Forestation
CDD	Cooling Degree Days
P	Average Precipitation
N	Number of Customers

COST DRIVER	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
NMD	-0.152	-3.975	0.000
NMDNMD	-0.067	-0.709	0.479
PF	0.255	8.932	0.000
PFPF	0.104	5.280	0.000

COST DRIVER	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
CDD	0.097	3.525	0.001
CDDCDD	-0.033	-1.805	0.072
P	0.232	5.015	0.000
PP	0.081	2.029	0.044
NN	0.034	4.286	0.000
Trend	-0.010	-2.079	0.039
Constant	0.217	4.732	0.000
Rbar-Squared	0.394		

Sample Period	Varies, typically 2003-2008
Number of Observations	248

Table 12

Comparison of PGE's Reliability Variables To Full Sample Norms

Business Condition	Units	Mean Values 2006-2008 PGE	Mean Values 2006-2008 Full Sample	PGE Mean/Sample Mean
SAIDI	Minutes	71.835	147.448	0.49
SAIFI	Count	0.727	1.264	0.58
Customers per Distribution Line Mile	Ratio	45.228	37.956	1.19
Percent Distribution Plant Overhead	Percent	0.56	0.63	0.90
Percent of Service Teritory that is Forested	Percent	0.63	0.40	1.57
Cooling Degree Days	Degree Days	465	1103	0.42
Precipitation	Inches	37.37	38.75	0.96
Number of Customers	Count	800,324	925,436	0.86

Table 13

Comparison of Actual and Predicted SAIDI for PGE

Year	Difference (%)
2006	-68.8%
2007	-72.1%
2008	-61.1%
2006-2008 Average	-67.4%

Table 14

Comparison of Actual and Predicted SAIFI for PGE

Year	Difference (%)
2006	-46.7%
2007	-53.0%
2008	-43.0%
2006-2008 Average	-47.6%

benchmark on average over the last three years of the sample, 2006-2008, while its average SAIFI value was about 48% below its benchmark over the same time period. We rejected, at a 90% confidence level, the hypotheses that PGE was an average SAIDI and SAIFI performer during these years. We conclude instead that PGE was a significantly superior reliability performer.

APPENDIX

This section provides additional and more technical details of our empirical research.

Form of the Model

Specific forms must be chosen for functions used in econometric research. Forms commonly employed by scholars include the linear, the double log and the translog. Here is a simple example of a linear cost model. For each company *h* in year *t*,

$$C_{h,t} = a_0 + a_1 \cdot N_{h,t} + a_2 \cdot W_{h,t} \quad [A1]$$ [16]

Here is an analogous cost model of double log form.

$$\ln C_{h,t} = a_0 + a_1 \cdot \ln N_{h,t} + a_2 \cdot \ln W_{h,t} \quad [A2]$$

The expression "ln" here indicates a natural logarithm. In a double log model the values of the dependent variable and both business condition variables are logged. This specification has the effect of making the parameter corresponding to each business condition variable the elasticity of cost with respect to the variable. For example, the a_1 parameter indicates the % change in cost resulting from 1% growth in the number of customers. Elasticity estimates are informative and make it easier to assess the reasonableness of model results. It is also noteworthy that, in a double log model, the elasticities are *constant* in the sense that they are the same for every value that the KPI and the corresponding business condition variables might assume.[17] This is restrictive, and may be inconsistent with the true form of the relationship that we are trying to model.

Here is an analogous cost model of translog form

$$\begin{aligned} \ln C_{h,t} &= a_0 + a_1 \cdot \ln N_{h,t} + a_2 \cdot \ln W_{h,t} + a_3 \cdot \ln N_{h,t} \cdot \ln N_{h,t} \\ &\quad + a_4 \cdot \ln W_{h,t} \cdot \ln W_{h,t} + a_5 \cdot \ln W_{h,t} \cdot \ln N_{h,t} \end{aligned} \quad [A3]$$

This form differs from the double log form in the addition of quadratic and interaction terms. Quadratic terms such as $\ln N_{h,t} \cdot \ln N_{h,t}$ permit the elasticity of cost with respect to each business condition variable to differ at different values of the variable. The elasticity of cost with respect to the output variable may, for example, be lower for a small utility than

---

[16] The terms in this model were defined in the footnote on page 8.
[17] Cost elasticities are not constant in the linear model that is exemplified by equation [A1].

for a large utility that has exhausted its opportunities to realize incremental scale economies. Interaction terms like $\ln W_{h,t} \cdot \ln N_{h,t}$ permit the elasticity of cost with respect to one business condition variable to depend on the value of another such variable. For example, the elasticity of cost with respect to growth in the number of customers served may depend on the price of labor in the service territory.

The translog form is an example of "flexible" functional form. Flexible forms can accommodate a greater variety of possible relationships between KPIs and the business condition variables. A disadvantage of the translog form is that it involves many more variables than simpler forms such as the double log. As the number of variables subject to the translog treatment increases, the precision of a model's parameter estimates falls. It is therefore common to limit the number of variables in a cost model that are translogged.

In this study, we have tried to strike a balance between the flexibility of the functional forms and the desire for statistically significant parameter estimates. We do this by limiting the translog treatment to variables that are predicted to be cost drivers in economic theory. Most other variables are simply logged.[18]

Estimation Procedure

A variety of estimation procedures are used in econometric research. The appropriateness of each procedure depends on the assumptions that are made about the distribution of the error terms. The estimation procedure that is most widely known, ordinary least squares ("OLS"), is readily available in over the counter econometric software. Another class of procedures, called generalized least squares ("GLS"), is appropriate under assumptions of more complicated error specifications. For example, GLS estimation procedures can permit the variance of the error terms of cost models to be heteroskedastic in the sense that they vary across companies. Variances can, for example, be larger for companies with large operating scale.

Estimation procedures that address *several* of the error term issues that are routinely encountered in utility benchmarking are not readily available in commercial econometric software packages such as Gauss and Stata. They require, instead, the development of customized estimation programs. While the cost of developing sophisticated estimation

[18] We have elected not to log a few of the variables that assume a value of zero.

procedures that are tailored for benchmarking applications is sizable, the incremental cost of applying them to different utilities is typically small once they have been developed.

In order to achieve a more efficient estimator, we used a GLS estimation procedure that corrected for autocorrelation and heteroskedasticity in the error terms. These are common phenomena in statistical cost research. The estimation procedure was developed by PEG Research using the GAUSS statistical software program. Since we estimated these unknown disturbance matrices consistently, the estimators we eventually computed are equivalent to Maximum Likelihood Estimators (MLE).[19] Our estimates thus possess all the highly desirable properties of MLEs. Note also that cost and cost share equations were estimated simultaneously, and our regression procedure allows for correlation between the error terms of these equations.

Note, finally, that the model specification was determined using the data for all sampled companies, including PGE. However, computation of model parameters and standard errors for the prediction required that the utility of interest be dropped from the sample when we estimated the coefficients in the predicting equation. This implies that the estimates used in developing a model will vary slightly from those in the model used for benchmarking.

[19] See Dhrymes (1971), Oberhofer and Kmenta (1974), Magnus (1978).

REFERENCES

Breusch, T. and A.R. Pagan (1980), “The LaGrange Multiplier Test and Its Applications to Model Specification in Econometrics,” *Review of Economic Studies*, 47 pages 239-54.

Buse, A. (1982), “The Likelihood Ratio, Wald and LaGrange Multiplier Tests: An Expository Note,” *The American Statistician*, 62 pages 153-7.

Dhrymes, P.J. (1971), “Equivalence of Iterative Aitkin and Maximum Likelihood Estimators for a System of Regression Equations,” *Australian Economic Papers*, 10 pages 20-4.

Guilkey, et al. (1983), “A Comparison of Three Flexible Functional Forms,” *International Economic Review*, 24 pages 591-616.

Magnus, J.R. (1978), “Maximum Likelihood Estimation of the GLS Model with Unknown Parameters in the Disturbance Covariance Matrix,” *Journal of Econometrics*, 7 pages 281-312.

Mundlak, Y. (1978), “On the Pooling of Time Series and Cross Section Data,” *Econometrica*, 46 pages 69-85.

Oberhofer, W. and Kmenta, J. (1974), “A General Procedure for Obtaining Maximum Likelihood Estimates in Generalized Regression Models,” *Econometrica*, 42 pages 579-90.

Zellner, A. (1962), “An Efficient Method of Estimating Seemingly Unrelated Regressions and Tests of Aggregation Bias,” *Journal of the American Statistical Association*, 57 pages 348-68.

PGE BENCHMARKING SURVEY SUMMARY OCTOBER 2009

Contact	Department	Benchmarking
Chris Sirpless	Sourcing & Contracts	Since the late 1990's . Coordinated by through UPMG (Utility Purchasing Management Group). Comparing SAC's best practices against other utilities; meeting with benchmarking participants on an annual basis to discuss a variety of supply chain subjects , and the sharing of ideas.
Cindi Devich	Safety & Health Resources	Varies by topic. For safety related benchmarking, we have data from 1997 - 2009; for Workers' Comp data from 2004 - 2008; Short Term Disability and LTD data from 2007 - 2008 Monitor programs/rates against other companies Solicit feedback through professional listservs to quickly attain information on various topics e.g. cell phone policies; pandemic plans; Update/design programs/plans
Dale Coyle	Biglow Canyon Wind Plant	Biglow participates Generation Excellence, see attached for 2009.
Dave Ford	Business Continuity and Emergency Management	We were trying to determine what organizational structure, reporting format, number of employees, costs, would be incurred by like sized utilities in order to best be planful and fully integrated with respect to business continuity planning. The objective was to improve company resiliency.
Dawn Mendenhall	HRIS and Project Management, Payroll	We were looking at bench marking to see how best of breed companies perform in payroll, where we were and how we could improve.
Elyssia Lawrence	Cash Remittance	The benchmarking purpose is to determine where PGE ranks next to other utilities in regards to cost per mail-in payments.
Gary Boswell	Safety & Training	Conduct annual review of data supplied by EEI.
George Kuiawa	Meter Services & Field Operations, Meter Services, Field Collections, Energy Recovery	2007 and 2008. (did 2004, 05, 06 in Billing Credit and Collections)

Jay Fischer	Trojan ISFSI	The benchmarking purpose was to check with other utilities who had set up an ISFSI organization to determine their staffing needs and other details associated with meeting the Nuclear Regulatory Commission (NRC) license requirements. The benchmarking ensured that minimum staffing was adequate, and still was in line with what other utilities were doing to meet their requirements.
Joe Feltz	Internal Audit Services	1. 2003 - survey of NW utilities IA staffing practices 2. Annual - assessment of PGE IA practices against IIA Professional Practices framework (industry attribute and performance standards)
Joyce Bell	Compensation and Benefits	HR Practices: 2003 - 2008 401k: Every year since 2005 Benefits: Every other year Health and Welfare Efficiency: Every year since 2006 Executive Compensation: Every year Broad-based Compensation: Nonexempt and exempt salary surveys every year Pay Practices surveys occasionally Severance Practices surveys occasionally NW Utility Wage Survey each year Bargaining wage survey each year
Kim Metcalf	Web Management Org.	ForeSee survey ranks us against others and we participate in the annual E-Source 'usability' assessment that compares us to other utilities. We also get information from Rick Weijo's group for some web items from JD Powers and MSI. In these cases, it is primarily other utilities.
Loren Mayer		The only benchmarking done at Boardman that I am aware of was for the economic competitiveness study back in the mid 90's, and Rates did some work maybe 5 years ago by comparisons through GADS, using NERC personnel.
Michaela Lynn	Meter Reading, Revenue Protection (ERU), Key Customer, Call Center, Payment Options	Provide comparative information and explore best practices in several areas such as Billing Exception processing, Bankruptcy practices, Write offs, etc.
Mike Dwyer	Port Westward Operations	For power plants, the key indicators are availability, forced outage rate, output (mwatts), and efficiency (usually heatrate in btu of fuel per kwhr).

Paige Haxton	PGE Foundation	To analyze how the PGE Foundation's funding and giving compare to our peer utility group. Benchmarking is used to see if we are in alignment with our peer groups funding and giving.
Rick Weijo	Customer Research & Analysis	We conduct the residential, general business and key customer satisfaction benchmarking for the company. We also support ForeSee (Web) transactional tracking and Customer Relationship Metric benchmark study of CSR's.
Terry Davis	Customer Contact Operations	The objectives of the assessment were: · Conduct a holistic assessment of call center operations identifying status, strengths and weaknesses · Create an inclusive long term vision for the call center operation that is customer centric and supports PGE business objectives · Instill the best practices of leading customer-focused organizations, including the utilities sector
William Valach	Investor Relations	We have 14 peer utilities (6 regional and 8 other peers). We benchmark a number of things: - Total shareholder return - Relative valuation - Total expected return - Research coverage - Investor base - Rate base per customer - Price to book, ROE, bond ratings and a number of other financial ratios

Examples in Operational Efficiencies

- **Customer Service and Delivery (CS&D):** In 2009, CS&D area took a system-wide approach. Managers were asked to implement cost efficiency measures. The goal was threefold: 1) to train and provide tools to managers to identify cost efficiencies, 2) have them implement at least one process improvement, and 3) tie incentives to their successes. Before choosing what to do, managers received training on business process mapping to identify key business processes to a business unit output and note all handoffs and decision points from the start of the process to the output. Managers were encouraged to identify a customer of their business unit and interview the customer on customer experience with the unit. The next step was to map the unit's processes using the tools. Within the business processes, the managers then identified inefficiencies or "pain points" and drilled down to identify potential improvements in quality of service and cost. Once the process was selected, mapped, and the streamlining or efficiency effort identified, the manager calculated the cost of implementation and the benefit of streamlining. Those processes which yielded net benefits were undertaken. A goal of this exercise was to inculcate this type of thinking into all managers and supervisors and lay the groundwork for continuous improvements.
- **New Install Customer Experience (NICE):** This improvement effort was focused on improving PGE's ability to meet customer requested connect dates, and decreasing work completed for jobs that customers ultimately end up canceling. The effort is expectto reduce by half job design hours for jobs that were cancelled before approval. The customer benefit is more certainty that

PGE will meet its desired connect date and better customer understanding of the process including when PGE is awaiting information from the customer.

- **Streamlining of distribution damage claims recovery process:** Prior to starting the process improvement, two PGE groups responded to customer inquiries concerning damage claims. The process was time consuming, frustrating for customers, and slowed down the time from the start of the claim to PGE recovery of damages due. The efficiency involved streamlining the claims process, including improvements to reduce aged receivables. One group now responds to customer claims inquiries; distribution aged receivables decreased by almost a million dollars, from $1.2 million in 2007 to $280,000 in 2009; the average invoice cycle time shortened from 80 days to 60 days; and the annual cost of claims processing went from 16,704 hours to 11,484 hours in 2009, enabling the redeployment of 2 FTEs. This improvement applied best practices used in companies with similar processes/work.
- **Direct access enrollment process improvements:** Nineteen PGE business units are involved in the direct access enrollment processes. The business units reviewed the processes which resulted in streamlining to assure a smoother ESS enrollment process and regulatory compliance.
- **Customer electronic payments:** In 2009, the number of customers paying electronically surpassed those with mail-in or walk- up payments. Electronic payments include Auto Pay, E-banking through the PGE Web site or IVR, or phone payments. At year end 2009, 49% of all customers and 54% of all residential customers pay electronically. Automated mail payments cost one to two cents more per payment to process. What this means in hard dollar savings

is that we have been able to reduce staffing over time in our mail-in payment processing operation (i.e. Cash Remittance). We eliminated one position in 2005, and eliminated another position in 2009 due to lower volumes of mail. The elimination of these positions saves PGE about $93,000 per year. The increase in customer electronic payments is attributable to work by several business groups including: customer service, corporate communications, customer research and analysis, the web team, market management and more.

- **Customer Technical Services and energy efficiency seminars for business:** When faced with increased demand from business customers and not enough PGE staff within the Customer Technical Services group, employees from other PGE business groups were recruited to help deliver the increased number of energy efficiency seminars for business customers. The aim of the seminars is to get business customers to adopt energy efficient technologies and equipment systems. As a result in 2009, the number of seminar attendees doubled and the number of employees knowledgeable about energy efficiency practices grew.
- **Agency Web Portal to ease energy assistance payments:** Starting in February 2010, agencies distributing Low Income Energy Assistance Program, Oregon Energy Assistance Program and Oregon HEAT funds are able to access customer information (with customer consent) as well as make commitments on customer accounts through the online agency portal. The agency representative will no longer have to speak to a customer service representative to obtain customer information on arrearage or shut off. Instead the agency representative, with the customer's consent, can access the customer's information directly, check the customer's account status and make an agency

payment commitment to the customer's account. When an agency makes a commitment on the account, it will be immediate. Provided the commitment is made prior to the day of disconnect and covers the amount due to avoid disconnection, the shutoff will be voided. The agency avoids having to call PGE for the information and has direct access. PGE has fewer agency calls, avoids manual entry of commitments into the Customer Information System (which prior to the portal arrived by fax), the payments are immediately noticed, and any shut off activity stopped. The customer receives more efficient service for energy assistance.

- **Employee Compensation Generally:** PGE actively controls costs in many ways, among them: targeting our compensation attributes and costs to reflect market median conditions; actively negotiating with health care insurance providers for the lowest plan rates; offering an employee wellness program, "Fit For Life," which emphasizes good overall health; and having employees share the cost of their health care. The wellness program is designed to address employee health risk factors that then drive health care cost increases over the longer run. Decreasing health risk factors help contain increasing health care costs.
- **Employee direct deposit of paychecks:** Starting in 2010, all job applicants, will be required, as a condition of employment, to have direct deposit for paychecks rather than paper checks. The avoided cost is $6.55 per paycheck. For current employees, we have been successful in efforts to have 90% or 2,500 of our employees opt for direct deposit of paychecks rather than paper checks.

Oregon law, ORS 652.110, prohibits requiring the direct deposit of paychecks for current employees.

- **Decreasing internal mail runs** PGE outsourced internal mail runs in 1998. Starting in 2010, internal mail runs to five PGE locations are reduced from twice daily to one. This results in a $30,000 savings annually.
- **Dispatchable Standby Generation (DSG):** In exchange for PGE maintaining customer owned generators on their sites, PGE can support its operating reserve requirements and provide peaking resources for the system by having its customers with standby generators agree to allow PGE to use their generation in defined circumstances. The customer owned generators are connected to the grid and may supply capacity to the PGE system within 10-15 seconds upon PGE dispatch via a high-speed network. DSG customers receive the benefits from the provided maintenance, repairs and fuel and all PGE customers receive low cost capacity benefits and operating reserve savings. This program is a working demonstration of smart grid technology applied to reduce PGE's operation costs.
- **Heating Biglow Warehouse:** To mitigate the increasing and high cost of propane to heat the Biglow warehouse, we permitted and installed a waste oil burner that burns used motor oil and waste oil from wind turbines. The warehouse used a propane based radiant heating system. The heating costs averaged $600-900 per week during the winter of 2007-2008. The new system was designed and installed in early 2009 and has a less-than four year payback. Other benefits include environmental gains: recycling used oil onsite eliminated the possibility of accidental spills, improper disposal and vehicle emissions

generated during transport of used oil off-site; and superfund liability and any uninsured expense for proper disposal is eliminated.

- **Fleet Management:** As a result of a third party conducted fleet vintage replacement plan and benchmarking study, we found opportunities to standardize certain specific vehicles and help reduce acquisition costs. The purpose of the plan was to determine total cost of ownership and optimize maintenance and replacement of fleet vehicles. In reviewing our performance against 25 EEI member utilities' fleets, we found that PGE keeps fleet vehicles on the road longer than the industry average. We are using this as a baseline for examining asset utilization and redeploying underused assets.
- **Solar financing model:** PGE identified a long-term ownership option for solar facilities that is more cost efficient than if PGE were to build them and own them from the outset. The process involves finding an equity partner to provide most of the up front capital and receive the tax credits for the project over the eligible time period. At the end of that time period, the ownership transitions to PGE. Customers receive the benefit of the asset without the up front cost.
- **Port Westward and Coyote Springs' labor agreements:** The new Union contract was negotiated to have fewer employee labor specializations so that employees can work on a variety of work tasks at the plants. This translates to a leaner staff to run the plants.
- **Reliability Centered Maintenance (RCM):** RCM is used by the plants to reduce failures and breakdowns and increase plant reliability and availability. RCM studies operations, maintenance practices, patterns and trends to determine the optimum maintenance for a given system or piece of equipment.

When an unplanned outage happens at a plant, the increased costs include unplanned covering for power generated (purchased power), and employee overtime. Timing maintenance activities based on better information means more efficient running of the plants. A specific application of RCM involves the pulverizers at Boardman. RCM was used to decrease the amount of reactive maintenance done on the pulverizers at Boardman. The pulverizers grind coal into a fine powder for combustion in the boiler. The cost for maintenance between January and July in 2007 was $350,000. In 2009 the same costs were about $98,370. A similar analysis was undertaken for the reheater at Boardman. The reheater is a section of the boiler that takes steam, reheats it and sends it to the steam turbine. A reheater leak can take the plant offline for up to four days, costing PGE around $500,000 per day in replacement power cost. Through the RCM analysis, we were able to forecast expected reheater tube leaks in the coming years and justify the cost to replace the upper section of the reheater.

- **Postage savings with use of intelligent barcode:** The United States Postal Service (USPS) has introduced a replacement to the current Delivery Point Barcode that provides for much more data content and tracking capabilities, known as the Intelligent Mail Barcode (IMB). PGE's Print and Mail Services has rolled out the IMB with "basic service" by the end of 2009 which will allow for continued work-share discounts that equate to over $1.0 million dollars in annual cost avoidance. In 2010, the group saved an estimated $60,000 and reduced its budget accordingly.
- **Customer Service Representative Feedback Form Automation:** This improvement developed a specific form that customer service representatives

(and all employees) can use to submit customer feedback. Both forms include drop down menus that employees select to indicate categories and subjects. This information automatically populates the database and can be sorted by category or subject. Customer Relations staff no longer receives/prints emails or re-enters the same information already keyed by a CSR.

- **PGE's Power Operations and the "Web Trader" system:** The Power Operations group recently implemented a new system called WebTrader that combined the department's daily activities into one integrated system, managed by a third party and hosted off-site. Prior to this system, Power Operations was using three separate systems to manage daily activities. PGE was paying for license agreements for all three systems. PGE's IT department was supporting these systems.
- **AVL Auto Vehicle Locating:** GPS devices were placed in a subset of fleet vehicles to allow tracking of the vehicles through a vendor hosted website. The improvement over a manual tracking system allows PGE employees to readily identify where a specialized vehicle is for more efficient dispatch. In addition the tracking supports safety. If PGE was unable to reach a single man crew, for example, the vehicle could be located and someone could check on the welfare of the crew.
- **Derivatives accounting:** For financial reporting involving derivatives accounting, the software code was re-written to reduce the number of labor hours required to complete the report and increase accuracy. Increasing automation reduces the opportunity for human error. The time savings for

preparation and review is estimated at about a day's worth of work by an exempt employee, per month during the accounting close.

- **811 Partner with Home Depot:** As one means to decrease the amount of damages to underground facilities from digging, PGE partnered with Home Depot and 3,000 Oregon Home Depot employees were trained on the importance of calling 811 before digging to avoid damage to underground facilities. The training encouraged Home Depot employees to tell customers. In addition, informational key chains for keys to Home Depot rental equipment and brochures were distributed. While damages from digging have decreased, it is not possible to determine the impact of the Home Depot training and information.
- **Tax credits for fleet vehicles:** PGE is taking advantage of Federal and State Tax Credits for purchase of certain hybrid vehicles and plug-in hybrid technology. Oregon State Business Energy Tax Credits (BETC) can be up to 35% of the incremental cost of purchasing a hybrid vehicle and federal tax credits could result in up to $12,000 per vehicle. 2009 savings total approximately $34,270 from the tax credits.
- **Pre-purchase of diesel fuel:** Early in 2009, PGE saw an opportunity to pre-purchase a portion of the diesel fuel needed for fleet operations. We negotiated with a fuel supplier and were able to lock in a price for a volume of fuel at a fixed price. The vendor was able to store and deliver fuel as needed and PGE saved an estimated $80,000. Pre-purchasing unleaded fuel was investigated but no agreement was reached due to fuel storage and price volatility issues.

- **Using recycled oil in PGE vehicles:** In 2009, PGE started using recycled oil in our vehicles for a savings of $8,000 per quarter or $32,000 annually. The oil is cleaned and additives added back in and it is re-used.
- **Discontinuing Dun and Bradstreet report:** PGE's wholesale credit business group decided to no longer routinely obtain a Dun and Bradstreet (D&B) report on every counterparty. Instead the need was challenged, asking whether the D&B report added information to the analysis or whether they had enough information. The D& B reports are about $100 each. This is not a big ticket item but rather an example of a culture shift to not do what has always been done before but think and challenge the status quo.
- **PGE's reuse center:** PGE uses a large quantity of office supplies. To allow for re-use when the supplies are usable, PGE created a "simply reuse" center. Items include binders, hanging file folders, tape dispensers, desk trays, staplers, calculators, markers, pens, pencils, paper clips, binder clips, and many other items. The center offers to employees a place to send items for reuse and a center to pick up items to be reused. The center also uses a high school intern to maintain the center, the database, and the delivery of items to employees. The net savings from re-using office supplies is less than $5,000 per year and helps infuse in employees an ethic of recycling and cost efficiency.
- **Tax department negotiations with Oregon Department of Revenue:** Negotiations with the Department of Revenue over the valuation attributed to PGE owned land near Pelton Round Butte, designated "flowage easement," resulted in an estimated $700,000 savings in 2009 The state agreed to lower the

valuation, which not only resulted in 2009 savings but sets a lower base for future years' property tax assessments.

- **IT contracts negotiation and management:** The IT group implemented a program several years ago to save costs by negotiating beneficial terms in IT contracts and assuring that negotiated terms are honored. For example, we have negotiated discounts for IT contractors, caps on many of our IT software licenses and maintenance agreements, and discounts on bundle purchases rather than individual and separate purchases. We estimate that we have saved, by paying less, an estimated $1.5 million between 2006 and 2009. The savings is conservatively calculated by comparing amounts PGE paid with amounts paid by others for the same products or by the vendor's best offered price.
- **Government Affairs and negotiation of franchise agreements:** Challenged with over forty five franchise agreements coming due over a four year period, the Government Affairs group identified the franchise negotiation process as an opportunity to resolve longstanding and time consuming issues and build a better relationship with cities. The group assembled a cross functional project team of PGE employees from an array of business units, all of whom worked with cities in some way, e.g. streetlighting, system designers, corporate accounting, pole attachments, and others. The team created an optimal franchise agreement template for negotiation with cities. In addition, members of the team were prepared to participate as subject matter experts in negotiations. The project team brought a focused and coordinated approach to franchise agreements and minimized the need for PGE negotiators to seek information from the affected PGE business units during negotiations. The development of a

template also meant consistency in all the franchise agreements. Consistency saved time because the Government Affairs group does not have to train and communicate with employees on the applicable rules for one city versus another. Finally the project led to a more transparent process for which city customers expressed appreciation.

- **Labor agreement efficiencies:** PGE negotiates for work rule flexibility and efficiency and effectiveness. During the last bargaining with the Local 125, International Brotherhood of Electrical Workers union, PGE gained agreement to restructure the cost share of health care premiums for both active and retired employees. This included a new more efficient and consumer driven medical plan. In addition work rules for our first responders we modified to allow them to do non-traditional work without calling out a crew.

Examples in procurement cost efficiencies

- **Process efficiencies:** Electronic ordering and confirming receipt of supplies with our major T&D materials suppliers. PGE storekeepers enter requirements for materials into our system and orders are electronically dispatched to our suppliers. When materials are received, we confirm the receipt electronically. PGE has also achieved efficiencies in processing payments through the use of automatic payments based upon inventory receipts, saving the manual process of invoice matching.
- **Pole and line hardware:** Our supplier reviews their costs and profit margins with us annually. We work with them to control costs and if a supplier's profits exceed the agreed-upon target, the supplier agrees to a refund to PGE.

- **Biglow construction contract:** PGE avoided escalated construction materials costs of nearly $1.0 million in the Biglow Canyon phase 3 construction by negotiating with the contractor to start the work earlier than the Biglow phase 3 contract schedule provided. When construction for Biglow phase 2 was nearing completion, the Biglow phase 3 construction contractor requested that it be permitted to start work on Biglow phase 3 earlier than the contract provided. The contractor was interested in avoiding the costs of remobilizing staff several months in the future according to the Biglow phase 3 contact commencement date. As a condition of starting Biglow phase 3 early, we negotiated the reprising of materials, taking advantage of depressed commodity prices. In addition, the contractor agreed to purchase materials for Biglow phase 3 on its credit, avoiding cost escalations for materials originally built into the contract; and defer billing PGE for the materials until the original Biglow phase 3 contract milestone date. Had the contractor not started earlier, the materials would have been purchased much later at a higher expected cost. The avoided cost is calculated by subtracting the materials cost from the escalated future cost.

Table of Contents

I. Introduction

Q. Please state your names and positions with PGE.

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

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

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 present PGE's $1,811.0 million revenue requirement for the 2011 test period. On an average rate base of $3,243.6 million, this revenue requirement will allow PGE an opportunity to earn an 8.289% rate of return that includes a 10.50% return on average common equity of 50% in 2011. PGE Exhibit 301 summarizes the development of PGE's 2011 revenue requirement.

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

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

A. PGE's revenue requirement is $125.2 million higher in 2011 than the revenues we would expect based on 2010 prices, which reflect approved rates in UE 189, UE 197, UE 204, UE 208, and UE 209. Therefore, PGE requests that rates be adjusted on January 1, 2011, to yield $125.2 million of additional revenues (a 7.4% increase overall) on an annualized basis. PGE Exhibit 1500 describes the prices PGE proposes to allow an opportunity to recover our 2011 revenue requirement.

Q. Does the requested increase reflects the management discretionary items described in PGE Exhibit 100 to help limit the size of the requested increase?

A. Yes. We adjusted the revenue requirement to reflect the two items described in PGE Exhibit 100. The approximate revenue requirement impact of the adjustments total $23 million of reductions, as follows:

- Lowering our requested ROE from 11.0% to 10.5%: $(13) million
- Reducing our requested incentive costs to reflect the Commission's treatment in UE 197: $(10) million

Q. In addition to approving PGE's proposed 2011 revenue requirement, what additional requests does PGE have of the Commission in this case?

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

- Provide an accounting order that allows PGE to establish a regulatory balancing account to track differences between actual major storm damage costs and an accrual (or estimate) of storm damage costs. We propose that an initial estimate of storm damage accrual be set at $3.5 million for 2011. PGE Exhibit 1000 describes the current availability of storm damage insurance and PGE Exhibit 800 describes the basis for the accrual, the conditions under which actual major storm damage costs will be charged to the proposed account, and the underlying basis for making this request. We request that the proposed account accrue interest at PGE's authorized rate of return until the Commission approves amortization of the outstanding balance in a subsequent rate case. The Commission can review the prudence of costs included in the balancing account during the rate case in which PGE requests amortization.

- Provide an accounting order that allows PGE to establish a regulatory balancing account to track differences between PGE's estimated pension expense and the actual pension expense recorded on PGE's financial statements. The balancing account for pension expense is a component of PGE's proposed Automatic Adjustment Clause (AAC) tariff for pension related costs, which includes a return on contributions to the pension trust in excess of pension expense. We request that the proposed account accrue interest at PGE's authorized rate of return until the Commission approves amortization of the outstanding balance in a subsequent rate case. PGE Exhibit 500 explains the rationale for this request and further describes how the balancing account and AAC will function. PGE Exhibit 1501 provides a copy of the proposed Schedule 141.
- Provide an accounting order that allows PGE to track differences between the environmental mitigation and remediation costs as projected in this case for certain projects and the corresponding actual costs. We request that the proposed account accrue interest at PGE's authorized rate of return until the Commission approves amortization of the outstanding balance in a subsequent rate case. PGE Exhibit 700 describes this request in further detail.
- Provide an accounting order that allows PGE to accrue long-term debt costs on study costs of self-build options for IRP/RFP purposes. In addition, we request that the Commission allow PGE to create a future regulatory asset if we select an alternative project to a self-build option. Section II provides the rationale for this request and further describes the proposed accounting for such costs.

- Provide an order that allows PGE to account for the costs of collateral requirements related to power supply as net variable power costs (NVPC) for ratemaking purposes. PGE Exhibit 1100 describes this proposal in greater detail.
- Provide an accounting order that allows PGE to smooth the impact of O&M costs related to the Information Technology (IT) system replacement program (2020 Vision). This will allow PGE to spread the incremental development O&M over the life of the project, including both the development period and the amortization period and will significantly reduce the price impact of these costs as compared to including them in test year forecasts as they are expected to be incurred. PGE Exhibit 600 further describes the proposal and calculations.

Rate Increase Drivers

Q. Please discuss the impact of net variable power costs (NVPC) on PGE's overall request in this case.

A. PGE's initial forecast of NVPC for the 2011 test year is $747.2 million, or $40.3 per MWh of retail cost of service 2011 calendar year load of 18.5 million MWh. PGE's final 2010 NVPC forecast used to set rates in UE 208 was $784.1 million to serve 18.5 million MWh, or $42.1 per MWh of retail calendar year load. Thus, a decrease in unit NVPC is responsible for a decrease in revenue requirement of $32.6 million. The lower NVPC is included in the total $125.2 million base rate increase sought in this proceeding. NVPC are further described in PGE Exhibit 400.

Q. What other cost components are responsible for PGE's $125.2 million request in this proceeding?

A. Table 1 below itemizes the major sources of PGE's $125.2 million request in this proceeding.

Table 1
(Sources of Net Rate Increase)

Source:	**Approximate Rate Impact**
Investment and related costs, including ROE increase	4.25%
Higher O&M costs, including the impact of negative load growth since UE 197	5.15%
Impact of NVPC	(2.0)%
Overall 2011 Rate Increase	7.4%

PGE Results if No Rate Increase is Authorized

Q. In the absence of a rate increase, what is PGE's expected regulated ROE for 2011?

A. As shown in column 1 of PGE Exhibit 301, without a rate increase we would expect PGE's ROE to be approximately 6.0% in 2011.

Q. Does this level of ROE reflect the impact that Sentate Bill 408 (SB 408) would have on PGE if this rate case were not filed?

A. No. Absent this rate case, we would expect a significant customer refund under SB 408 due to the use of rate making ratios based on prior Commission proceedings (See Docket Nos. UE 197, UE 204, UE 208, and UE 209). The use of these ratios would result in presumed "taxes collected" under SB 408 far in excess of PGE's projected tax liability for 2011. Under the current SB 408 methodology, this "double whammy" would further reduce PGE's earned ROE in 2011 to approximately 4.5%.

Structure of the Case

Q. Does PGE's 2011 revenue requirement include the effect of any new generating resources for 2011?

A. Yes. This case includes the net revenue requirement of Biglow Canyon phase 3 in 2011. We expect Biglow Canyon phase 3 to begin operation in spring 2010, with all 76 turbines in the 175 MW capacity project in service by September 2010. PGE plans to file separately under the Renewables Adjustment Clause (RAC) Schedule 122 to defer the net revenue requirement impact of Biglow Canyon phase 3 during 2010. Section X discusses Biglow Canyon phase 3 in further detail, including the net revenue requirement impact of $29 million for 2011 or about 1.7%, which is a component of the overall increase of $125.2 million sought in this case.

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

A. Yes. Our 2011 revenue requirement in this case also includes the costs and benefits of PGE's AMI investment, which was previously reflected in docket UE 189. As a result, Schedule 111, which collects the net AMI revenue requirement, will be set to zero in 2011. Section III provides a summary of the status of the AMI project and supports the estimated savings of $16.5 million reflected in this case. In addition, this case includes PGE's investment in the Selective Water Withdrawal (SWW) facility at the Pelton Round Butte hydro project. The Commission recently approved a stipulation in a separate proceeding related to this investment (UE 204, Order No. 10-020) and rates went into effect February 1, 2010 through Schedule 121. PGE will use Schedule 121 to collect the Commission-approved revenue requirement through 2010. We will set Schedule 121 prices to zero in 2011 since we include those costs in our base rate proposal in this case.

Q. Please summarize PGE's 2011 revenue requirement.

A. Table 2 below summarizes PGE's 2011 revenue requirement by major category and provides a comparison to regulated utility actual results from 2008. We also list the PGE testimony that addresses the specific cost categories.

Table 2
(Revenue Requirement Summary in $000s)

Rev Req Category	2008 Actuals	2011 Test Year	Exhibit	No.
Sales to Consumers	$1,541,583	$1,810,997	Rev Req	300
Other Revenue	23,181	20,961	Rev Req	399
NVPC	662,284	747,192	Power Costs	400
Production O&M	89,235	123,316	Fixed Prod	700
Transmission O&M	10,757	12,621	T&D	800
Distribution O&M	69,642	84,075	T&D	800
Customer Service	68,660	71,044	Cust Svc	900
A&G	124,335	126,207	Corp Support/IT	600, 1000
Depr. &Amort.	207,503	232,564	Rev Req	300
Other Taxes	83,410	100,645	Rev Req	300
Income Taxes	59,398	65,447	Rev Req	300
Operating Income	189,540	268,846	COC	1100
ROE	9.38%	10.50%	ROE	1200

Q. Please describe Operating Income as used in Table 2 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 2011 revenue requirement?

A. We developed the 2011 revenue requirement based on PGE's 2010 budgets, and then escalated for inflation and known and measurable changes. PGE Exhibit 200 describes the steps taken to maximize organizational efficiency to mitigate the proposed rate increase, in addition to the management discretionary items previously described.

Q. What escalation rates did you use to escalate the 2010 budget to 2011?

A. We applied the following escalation rates to the 2010 budget:

- Union labor = 3.6% effective March 1
- Non-union labor = 3.9% effective April 15 for non-officers and May 1 for officers
- Outside services (CE 21, 26, 41, 49) = 1.4% effective January 1
- Direct materials (CE 31, 36) = 1.1% effective January 1
- Employee business expense (CE 61, 68) = 2.3% effective January 1

Q. What is the source 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 May 2009. Union wage escalation is based on the forecast of compensation costs described in PGE Exhibit 500.

Q. Did you adjust PGE's 2011 revenue requirement to reflect previous rate making decisions and other regulatory policies?

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

Table 3
(Regulatory Adjustments in $Millions)

Adjustment Item	O&M	Rate Base
Retail Services	$(0.1)	$(0.3)
Charitable Contributions	$(1.2)	
State & Federal Lobbying	$(1.3)	
Memberships and Dues	$(0.1)	
MDCP	$(7.5)	
SERP	$(1.6)	
Image Advertising	$(1.0)	
Total Adjustments	$(12.8)	$(0.3)

Q. Please explain these regulatory adjustments.

A. There are seven regulatory adjustments:

- Retail services: removed $0.1 million of O&M and $0.3 million of rate base per the SB 1149 unbundling rules;
- Charitable contributions: excluded the entire $1.2 million from cost of service;
- State and federal lobbying: excluded the entire $1.3 million from cost of service;
- Memberships and dues: removed $0.1 million which reflects the rate making treatment received in UE 197;
- Managers Deferred Compensation Plan (MDCP): removed the entire $7.5 million from cost of service;
- Supplemental Executive Retirement Plan (SERP): removed the entire $1.6 million from cost of service;

- Corporate image advertising: removed the entire $1.0 million from cost of service.

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

A. We compare our forecast of 2011 test year costs to 2008 actual costs. We perform these comparisons because 2008 was the last full year of actual cost information available. In addition, 2009 projected costs reflect unique circumstances due to economic factors and do not provide a reasonable base for comparing to 2011 costs. Nevertheless, we provide forecast 2009 costs in exhibits and work papers.

II. Preliminary Study Costs for Self Build IRP Options

Q. What costs does PGE incur to study or evaluate self build options related to the IRP?

A. PGE incurs costs associated with investigation, survey, and permitting in order to establish the feasibility of self-build projects and to establish cost estimates for such projects. The preliminary study activities include:

1) Analysis of the site and technology, including fueling, transmission and water feasibility studies;
2) Securing land agreements;
3) An assessment of environmental site considerations and permitting feasibility to obtain relevant state and federal permits; and
4) Preparation and filing of required documents for permitting.

Q. What is the current accounting treatment of such costs?

A. PGE currently records such costs in deferred accounts (FERC 183) on the balance sheet. If PGE selects its self build option from a Request for Proposal (RFP) and the project has received corporate approvals, we transfer the costs to Construction Work in Progress (CWIP, FERC 107) and accrue Allowance for Funds Used During Construction (AFDC). All of these costs are capitalized into the overall capital costs of building/acquiring the project and are recovered over the estimated useful life of the facility. However, if PGE selects an alternative resource bid into an RFP, the study costs initially recorded to the balance sheet are written off to O&M.

Q. How does PGE recover financing costs associated with self build study costs <u>prior</u> to having an approved project?

A. Historically we have not recovered such financing costs since the costs do not accrue AFDC, nor are we otherwise compensated for these costs.

Q. Does PGE development of a self build option benefit customers?

A. Yes, the development of a self build option benefits customers by providing an alternative to the bids of external parties.

Q. Do alternative bidders in an RFP recover their costs to develop bids?

A. Yes, over the long-term they must recover the costs of developing their losing bids, otherwise they would not remain in business. While alternative bidders in an RFP may also not be selected and hence may not recover the costs of developing a bid for a particular RFP, they must recover these costs through subsequent winning bids, otherwise they would not have a sustainable business. PGE seeks treatment on an equal footing with other going concerns that may bid in an RFP.

Q. Can't a "normalized" level of self build study costs be determined and included in your rate request?

A. No. The costs of developing a self build option are not easily forecast since they are dependent on the type of resource being developed (coal, gas, wind, etc.), as well as the size and operating characteristics of the potential facility. Further, PGE develops self build options in conjunction with RFPs for major resources, the timing or frequency of which cannot be readily predicted. Finally, such an estimate would require that we establish the probability of not selecting our self-build option, which is not reasonable.

Q. Is there a better regulatory response to these costs?

A. Yes. PGE should be allowed to accrue financing costs associated with all self build study costs from the time incurred, rather than just when a project has obtained internal approvals. Historically, our investors have not been compensated for this cost. Further, PGE should be allowed to recover these costs if our self build option is not selected both as a matter of fairness and to eliminate the appearance of incentives to self-select projects.

Q. What accounting treatment does PGE propose for self build study costs?

A. We propose to continue to record any self build study costs initially in FERC 183 as prescribed by the relevant Code of Federal Regulations (CFRs). However, we request that the Commission allow PGE to accrue long-term debt costs on the balance of costs in FERC 183 based on the Commission authorized long-term debt rate. If we select an alternative project to our self build option, we propose that we transfer any incurred self build study costs to a regulatory asset (FERC Account 182.2), with an amortization period over 5 years on a straight-line basis.

Q. For study costs transferred to FERC 182.2, when would amortization of such costs begin?

A. Amortization of amounts transferred to FERC account 182.2 would begin the following general rate case upon approval for amortization granted by the Commission.

Q. If PGE recovers self-build study costs, including accrued long-term debt costs, for resources not ultimately selected, does this create a potential violation of ORS 757.355 (i.e., the used and useful standard)?

A. Our request avoids this legal issue. We propose that any amounts transferred to FERC 182.2 exclude any previously accrued long-term debt costs and not be included in rate base in this or subsequent rate cases. As a result, the regulatory asset would not earn a “return on” in any fashion.

Q. Does PGE’s accounting proposal result in a change in costs that have been included in the 2011 test year revenue requirement?

A. No. PGE's incurred self build study costs for resources supported in the current IRP are still awaiting a determination from the Commission. We have not included a forecast of regulatory asset amortization for 2011 associated with this proposal.

III. Advanced Metering Infrastructure (AMI) Costs and Savings

A. Overview of AMI

Q. Please briefly describe the AMI system.

A. PGE is installing a smart-metering system that enables the automated collection of meter data via a fixed network. A complete AMI system consists of solid-state electronic meters; a communication system, or network, to transmit the data; and a communication server or computer system that receives and stores data from the meter, and as a two-way system, sends commands to the meter. This two-way capability enables the utility to send commands and updates to the meter or control devices at the customers' premises as well as receive signals regarding the meter's operating condition.

Q. Was PGE's AMI proposal resolved in a specific OPUC Docket?

A. Yes. In Docket No. UE 189, PGE, the OPUC Staff, the Community Action Partnership of Oregon (CAPO), the Oregon Department of Energy (ODOE), and Northwest Natural (NWN) reached a joint stipulation to adopt PGE's proposed system, which was then approved by Commission Order No. 08-245. This order also included a Conditions Document (Appendix A, pages 10-21) that specified certain commitments that PGE would fulfill to: implement customer and system benefits, coordinate with CAPO and NWN, and provide status reports and plan updates.

Q. How much will the system cost compared to your initial estimates and when will it be completed?

A. At the time of the Joint Stipulation, PGE estimated that the fully deployed system would total approximately $132.2 million in capital costs. Based on our most recent estimate, we still believe this to be the amount that will close to plant by year end 2010, when the system will be fully deployed.

Q. Please summarize the types of benefits the system will provide.

A. The system is expected to provide two types of benefits: operating benefits and customer and system benefits. We describe them briefly as follows:

- Operating benefits – the benefits that PGE achieves from the system as installed. The primary component of this is the workforce reduction achieved by eliminating most meter reading positions and many field credit representatives.
- Customer and system benefits – the benefits to be derived from additional programs that can take advantage of the technological platform and new information that the AMI system provides. These programs involve additional costs and will only be implemented if and when economical to do so. The primary component of this is demand response.

B. Operating Benefits

Q. How much does PGE currently estimate it will achieve in operating savings due to AMI?

A. Based on our most recent estimates, PGE believes we will achieve approximately $16.5 million in operating benefits in 2011, the first year after full deployment. Table 4 below provides a summary of the savings in 2011.

Table 4
(Summary of AMI Operating Benefits in 2011)

Category	$000
127.5 FTE reduction (net of incremental FTEs)	10,293
Contractor reductions	207
Overtime reductions	410
Material and supplies	441
Fuel and maintenance	1,057
Late pay fees	2,000
Power costs from remote disconnects	1,126
Additional billings from lost revenue protection	1,614
Improved Meter Accuracy	524
Power price delta	327
Incremental IT (non-labor)	(553)
Incremental system costs	(533)
Incremental communication costs	(370)
Total Operating Benefit	16,544

Q. Has PGE reflected these savings in its 2011 forecast?

A. The first six items in Table 4 are included in the specific O&M and other revenue categories by responsibility center and PGE ledger (see work papers to this Exhibit). The power cost and most of the additional billing benefits have been incorporated in the test year through PGE's load forecast. Three items are currently not reflected in the 2011 forecast. First, the MWh associated with $300,000 of the $1.6 million attributable to lost revenue protection have not yet been incorporated into the load forecast discussed in PGE Exhibit 1400. PGE will include this increment in the load forecast update for this filing.

Q. Were any other items not included in the load forecast?

A. Yes. The second item not included in the 2011 forecast relates to improved meter accuracy. PGE is currently evaluating the specific difference in kWh attributable to the change in meters and we expect that review to be completed before the next load forecast update. At that time, we can include the latest estimate into the test year forecast. We note that the UE 189 estimate is still valid absent additional information.

Q. What is the third item that was not included in the rate case filing?

A. The third item is the power cost benefit associated with changing power prices. This specifically refers to the fact that the dollar benefits that we expect to achieve for the remote connect/disconnect function is directly related to both the MWh savings and the price for power that we avoid purchasing at the margin. In early 2008, at the time of the UE 189 Joint Stipulation, power prices were estimated to be approximately $66/MWh in 2011. Since then, the recession has resulted in lower power prices and we currently estimate them to be approximately $51/MWh in 2011. Because power prices are beyond PGE's control, we note this aspect of energy-related benefits as being temporarily unavailable but in the future, it is fully achievable.

Q. How does the current level of benefits compare to the UE 189 estimates?

A. On the whole, PGE estimates that we will achieve or exceed the savings projected at the time of the Joint Stipulation with the exception of two items. First, we expect to achieve the estimated savings from power costs related to the remote connect/disconnect function, except for the component related to power prices. As noted above, we expect this is a temporary shortfall and not within PGE's control. The primary area in which we currently believe that we will not achieve the projected benefits is from lost revenue protection (LRP – also referred to as unaccounted for energy in UE 189).

Q. Why do you believe you will not achieve these benefits?

A. At the time we were evaluating AMI's impact in UE 189, we had minimal empirical evidence on which to base an assumption regarding the improvement in MWhs captured through LRP (determined as a percent of total load). A couple of studies indicated that a wide range of LRP benefits was possible but PGE did not have a rigorous basis for choosing the benefit level. In order to be conservative, PGE assumed that AMI would increase LRP savings from 0.10% of total load to 0.25%. In settlement discussions, Staff indicated a preference for the LRP impact to be increased from 0.10% to 0.30% of load. The combined impacts were calculated at that time as an estimated benefit of $3.6 million in 2011 based on 55.2 thousand MWh savings at a $65.74/MWh price (i.e., assumed to be a power cost savings based on 18.7 million MWh load with 98% ramp-up).

Q. What is the basis for the benefit you are attributing to AMI?

A. Based on our experience to date, PGE currently believes that this level of MWh benefits is not realistic for two reasons. First, the baseline level of LRP assumed as the status quo in UE 189 was also based on limited external studies and was too low. More recent evaluation by PGE indicates our existing efforts are much more effective and efficient so that we currently estimate the baseline to be approximately 31.9 thousand MWh rather than 18.4 thousand MWh. The second reason is that the LRP benefit we believe is achievable with AMI is approximately 47.0 thousand MWh, which equals 0.24% of retail load. This results in an AMI benefit of 15.1 thousand MWh, of which 12.3 thousand MWh are reflected in current load forecast and 2.8 thousand MWh will be reflected in the load forecast update.

Q. Is LRP really a power cost benefit?

A. No. It represents an increase in discretely billable energy to specified customers offset by a reduced line-loss factor, which keeps power costs constant. This means that the same amount of power costs will be spread over a higher total load so that all customers will not have to pay for the extra energy otherwise attributable to specific customers. Consequently, the incremental LRP benefit totals $1.6 million because we multiply the 15.1 thousand MWh benefit times the weighted average retail rate (less the customer charge component) for Schedules 7 and 32.

Q. Will PGE re-evaluate the LRP benefit in the future?

A. Yes. Our estimate is based on more current expectations compared to the estimate derived two years ago. After we complete AMI deployment and have the advantage of evaluating the LRP benefit from actual experience, we will update our load forecast with the benefits as actually achieved.

Q. Are there any other benefits that you can associate with AMI?

A. Yes. PGE has also been awarded $3.5 million in business energy tax credits (BETCs) for reduced energy costs due to the elimination of meter reading vehicles and associated fuel consumption.

Q. How economical is AMI, based on the current level of estimated benefits?

A. If we assume the forecasted level of 2011 benefits is extended forward at the same rate of increase as calculated in the joint stipulation work papers, the net present value (NPV) benefit of AMI is approximately $21.4 million over the 20-year life of the project.[1]

Q. Is this a reasonable assumption?

A. Yes, we believe so. First, most of the benefits are from workforce reductions that PGE has incorporated in its forecast because we fully expect to realize them in 2011. Second, any additional benefits derived from AMI will enhance the $21.4 million NPV.

Q. To what additional benefits are you referring?

A. Achieving LRP benefits beyond the current assumption is a possibility, after we have historical data to review. More significantly, however, the customer and system benefits provide a significant source of additional benefits from AMI, particularly demand response.

C. Customer and System Benefits

Q. What types of additional programs are envisioned as customer and system benefits?

[1] The BETCs are included in the NPV calculation only for the five years to which they apply and correspond to 2011 in the same manner as incorporated in PGE's test year revenue requirement.

A. Customer and system benefits consist of the following:

- Demand response, including critical peak pricing (CPP)
- Distribution asset utilization, including:
    - Avoided service transformer failures
    - Proper transformer sizing
    - Early notification, to permitting agencies, of energy consumption exceeding customers' constructed electrical capacity (i.e., actual load exceeding safety margins at the customer's premises).
    - Delayed feeder conductor work
- Information driven energy savings (IDES)
- Outage management, including:
    - Avoided trouble calls
    - Faster one-premises outage response
    - Improved storm management
    - Faster fault location identification

Q. What is the ultimate significance of the customer and system benefits?

A. As noted above, AMI provides two types of benefits. Operating benefits are derived from the system as installed and tend to be available first in the form of reduced O&M costs. Customer and system benefits are informational savings that tend to come later and include the use of the smart meter infrastructure through either the communications capability and/or the interval data capability. Because the customer and system benefits have the potential to be very significant, they were addressed in the UE 189 conditions document to ensure their eventual pursuit.

Q. Have you included any of the customer and system benefits in the 2011 test year forecast?

A. No. PGE does not expect to have any programs operating in 2011 at a level where material benefits are realized.

IV. Other Revenue

Q. What is PGE's 2011 forecast of other revenue and how does it compare with prior years?

A. PGE forecasts 2011 other revenue of $20.9 million. This compares to 2008 actual other revenue of $20.6 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 5 below.

Table 5
(Other Revenue in $Millions)

Other Revenue Item	**2008 Actuals**	**2011 Forecast**
Utility Property Rental	6,048	6,190
Intertie/Other Transmission	7,029	4,980
Late Payment Interest	801	2,800
Steam Sales	2,097	2,319
Other Misc. Revenues	4,583	4,672
Totals	20,558	20,961

Q. Did you make any adjustments related to other revenue for the 2011 test year?

A. Yes. We adjusted the 2011 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 2011. Due to reduced Direct Access activity forecast for 2011, these revenues are approximately $1.0 million less than 2008 actual revenues. Second, new Environmental Protection Agency (EPA) regulations are under consideration that may prohibit the sale of fly-ash from our Boardman facility and require that such ash be designated as a hazardous waste with corresponding disposal requirements. To reflect this potential, we have removed approximately $0.5 million from 2011 test year other revenue and we have added fly-ash disposal costs in production O&M. Finally, we have added $2.0 million in late payment revenue related to the AMI project and reflected in Table 4 in the previous discussion of AMI benefits.

V. Depreciation

Q. What is PGE's estimate for 2011 depreciation expense?

A. We estimate $216.3 million in depreciation expense for the 2011 test year. As previously mentioned, this includes depreciation expense related to AMI and Biglow Canyon phase 3. PGE Exhibit 303 summarizes the test year depreciation expense by plant type and provides a comparison to actual 2008 and forecast 2009 depreciation amounts.

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

A. Yes. PGE filed the study, docketed UM 1458, in November 2009. The study revised estimates of lives, salvage value assumptions, and ultimately, depreciation rates by asset group. PGE proposes that the new depreciation rates go into effect on January 1, 2011.

Q. Please summarize the changes in depreciation method encompassed in the study filed in UM 1458?

A. PGE is proposing to extend the life span methodology, which was approved for all steam and combustion plant assets in UM 1233, to all wind generation assets. The terminal date for life span depreciation rate derivations will initially be set for the end of the final lease extension. With an average life of 27 years, the assignment of the life span methodology will initially have no impact on current depreciation rates for wind generation assets. PGE also proposes that the Commission prescribe depreciation rates, consistent with the common standard in the industry, rather than depreciation parameters. Finally, PGE is proposing to update expected useful service lives and net salvage rates. A copy of the study filed in UM 1458 is provided in our work papers.

Q. Is your estimate of 2011 depreciation expense consistent with the results of the depreciation study filed in UM 1458?

A. Yes, except for one adjustment. We used the depreciation rates from the study to estimate 2011 depreciation expense, consistent with the forecast of plant in service amounts through 2011. However, we reduced the resulting 2011 depreciation expense forecast by $10 million.

Q. Why did you reduce the 2011 test year estimate of depreciation by $10 million?

A. Given PGE's experience in prior depreciation study proceedings, and based on preliminary discussions with Staff, we believe that a likely outcome in the depreciation study docket will result in modified depreciation parameters that will reduce 2011 depreciation expense.

Q. Will PGE true-up estimated 2011 depreciation to reflect the final Commission Order in UM 1458?

A. Yes. PGE will update 2011 depreciation expense to reflect the Commission's decision in UM 1458.

Q. What impact does the new depreciation study have on 2011 depreciation expense?

A. The proposed depreciation rates as filed in UM 1458, assuming Boardman's current life assumption through 2040, increase depreciation expense in 2011 by $8 million, relative to the last approved depreciation study in UM 1233. The impact by asset class is provided in PGE Exhibit 304.

Q. What are the primary drivers of the $8 million increase under the new study?

A. The primary driver of the increase is the $11 million related to specific studies of likely hydro decommissioning costs, performed for all of PGE's owned hydro resources. Other changes are largely offsetting, with lengthened asset lives reducing annual depreciation expense while updates to net salvage assumptions increase annual depreciation expense.

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

A. We use a 2040 end of life assumption for Boardman to develop the base revenue requirement in this case.

Q. On January 14, 2010, PGE indicated that it is pursuing a modified operating plan for Boardman in the IRP process (Docket LC 48) that involves implementation of more limited pollution control equipment and closure of the plant in 2020. Why have you instead filed for rates consistent with a 2040 closure assumption?

A. As indicated in the correspondence to the Commissioners dated January 14, 2010, the stakeholders in the IRP process must work together to overcome barriers for PGE's plan to be feasible. Given the uncertain outcome of this matter, we believe the best assumption, under current conditions, is to maintain the current 2040 end of life date for proposed rates at this time.

Q. What if the Commission decides to implement either PGE's proposed 2020 plan, or an alternative shut-down plan such as 2014 closure?

A. To preserve the Commission's flexibility and to allow PGE to reflect in prices the impact of a Commission decision to shorten the life of Boardman (relative to the current 2040 assumption), we have filed a Boardman Depreciation Revenue Requirement tariff (Schedule 145) in this proceeding. The purpose of the tariff is to allow the Commission to authorize changes in prices to reflect the incremental revenue requirement impact of a shortened Boardman operating life. Base prices will reflect the revenue requirement based on a 2040 end of life of Boardman. PGE will collect the net effect of Commission-ordered changes to this life assumption through Schedule 145 upon approval by the Commission. A copy of Schedule 145 is included in PGE Exhibit 1501.

Q. Can you provide an estimate of the additional revenue requirement that would be collected through Schedule 145 if the Commission approved either a 2014 or 2020 closure date for Boardman?

A. Yes. If the change were effective January 1, 2011, and based on the un-depreciated Boardman investment in this case, the additional 2011 revenue requirement collected through Schedule 145 would be approximately $53 million (a 2011 rate impact of about 3%) under the 2014 shut-down scenario and $14 million (a 2011 rate impact of about 0.8%) under the 2020 plan. However, in the event of a Commission determination that the operating life of Boardman be reduced from 2040, we would seek to update the estimate of Boardman decommissioning costs to reflect a site specific study of Boardman prior to implementing Schedule 145.

Q. Are there other costs associated with shutting down Boardman?

A. Yes. PGE would need to replace the energy generated from Boardman with new purchase power agreements or additional generating resources. The estimated rate impacts noted above for proposed Schedule 145 under a 2014 or 2020 closure scenario do not contain any of these costs.

Q. What pollution control equipment for Boardman do you forecast in this rate case?

A. PGE will install low nitrogen oxide burners[2] (NOx) at the Boardman facility during the maintenance outage in 2011. The equipment will be in service by June 2011, after the maintenance outage scheduled for Boardman. The projected close to plant amount for this equipment is $29 million.

[2] This case was developed assuming that mercury control equipment would be installed in 2012, consistent with the 2040 operating life assumption. If the Commission adopted a 2020 closure, this project would occur in 2011 during the maintenance outage. Incorporating this into Schedule 145 would increase rates 0.1% relative to current rates if implemented 1/1/2011.

VI. 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 assets generally appears in rate base and earns a return at the allowed rate.

Q. Please summarize PGE's 2011 amortization expense.

A. PGE Exhibit 305 details the total 2011 amortization expense of $16.3 million, which we summarize in Table 6 below.

Table 6
(Amortization in $millions)

Amortization Item	2008 Actuals	2011 Test Year
Software Amortization	10.2	11.8
Other Intangible Amortization	4.1	6.1
Trojan Decommissioning	4.6	3.5
Other Reg Debit Amortization	16.5	4.1
Other Reg Credit Amortization	(4.3)	(9.2)
Total Amortization	31.2	16.3

Q. Please explain the amortization of software included in PGE's 2011 amortization expense.

A. Total software amortization is $11.8 million, which represents the amortization of capitalized software, recorded in FERC Account 303 and generally amortized over a 5-year period.

Q. Please describe Other Intangible amortization.

A. Other Intangible amortization includes hydro relicensing amortization and miscellaneous other intangible plant amortization. For hydro relicensing, this represents the recognition of annual costs associated with non-construction projects that have closed to plant in service.

Generally, these costs are amortized over the life of the new license. PGE Exhibit 700 further describes these capital costs.

Q. Why is Other Intangible amortization approximately $1.8 million higher in the 2011 test year than either 2008 actual or forecast 2009 results?

A. PGE forecasts the closure of approximately $65 million of capitalized costs during 2010 upon receipt of a new FERC license for the Clackamas hydro projects. PGE amortizes these costs over a 45-year period, which contributes $1.6 million of annual amortization. PGE Exhibit 700 provides further details on our efforts to obtain a new license for the Clackamas projects.

Q. Are any new intangible property related amortizations included in this filing relative to UE 197?

A. Yes. PGE expects the first phase of the 2020 Information Technology system replacement program (2020 Vision) to close to plant in service at various dates in 2011. PGE Exhibit 600 discusses the program in detail. PGE proposes amortizing this software over a 10 year period in the depreciation study. The Biglow Canyon phase 1 projects increase amortization expense by $1.1 million in 2011.

Q. Please summarize the outcome from the last docket in which PGE changed its Trojan Nuclear Decommissioning Trust (NDT) collection rate (UE 180).

A. In Order No. 07-015, the Commission authorized: 1) the annual amount collected in rates to be reduced from $14.04 million to $4.65 million, 2) that PGE may return to customers $20 million from the Decommissioning Trust, and 3) PGE to continue collecting funds from customers until Trojan decommissioning is complete.

Q. Did PGE recommend any changes in the amount to be collected from customers in its most recent general rate case (UE 197)?

A. No. We performed an analysis of the annual accrual, updated for the latest trust balances, expected rate of return on trust assets, cost estimates, and other parameters. This analysis indicated that no change in the UE 180 approved accrual of $4.65 million was required.

Q. Does PGE recommend any changes in the amount to be collected from customers in this proceeding?

A. Yes. We recently updated the analysis described above, and recommend that a reduction to the UE 197 approved accrual be made. Based on this analysis and the considerable uncertainty associated with the spent fuel at the Trojan site, PGE proposes a lower annual accrual rate of $3.5 million, a $1.15 million reduction.

Q. Please elaborate on the uncertainty.

A. Costs associated with the spent fuel at the Trojan site are the largest remaining decommissioning costs. The future of the spent fuel has been uncertain for years as the development and opening of the Yucca Mountain repository has been subject to continued delays. Recently, the Obama Administration announced that it intends to terminate the Yucca Mountain project and convened a blue-ribbon commission to develop and examine alternatives. This commission is expected to provide a final report detailing its recommendations within 24 months[3]. Given the additional delay in the U. S. Department of Energy taking possession of Trojan's spent nuclear fuel, PGE believes it is appropriate to support an accrual rate of $3.5 million per year.

Q. What decommissioning activity has been accomplished since UE 197?

[3] http://www.energy.gov/news/8584.htm

A. PGE has completed the demolition of the containment building and early demolition of seven additional structures (Trojan Central Building, Maintenance Building, Solids Settling Basin, South Warehouse, Fish Rearing facility, Environmental Lab Concrete Slab, and 33-ft Meteorological Tower Concrete Slab). PGE has no further planned decommissioning demolition work until after the spent nuclear fuel has been removed from the site.

Q. Has the Colstrip Common Facilities amortization changed for 2011?

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

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

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

Q. Do you propose to change the Coyote major maintenance accrual for 2011?

A. No. The previously approved $2.0 million accrual was recently established and should provide for recovery of major maintenance costs over a multiple-year period during which major maintenance activities are expected to occur. We will re-evaluate the accrual level in a future case. An estimate of the 2011 average balance in the balancing account of $4.1 million is also included in rate base.

Q. What major maintenance activities are expected at Coyote during 2011?

A. In 2011 we will perform major inspections on the gas turbine, steam turbine and generator. This work occurs every 48,000 hours of operation and is the most significant of the major maintenance activities that take place at Coyote.

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

A. No. We continue to support the use of the deferral mechanism for actual utility property sale gains and losses originally approved in UE 115. Since actual gains/losses will be deferred and refunded/collected through a supplemental tariff, we do not include any cost of service reduction in the 2011 test year.

Q. What are equity issuance fees?

A. Equity issuance fees are the costs associated with issuing additional shares of common equity. As discussed in PGE Exhibit 1100, PGE anticipates issuing $300 million of equity in 2011. PGE estimates the fees at 3.5% of the issue total, or $10.5 million in 2011. Further, equity issuance costs are recorded on the balance sheet as reductions in shareholder equity under GAAP and are not expensed for either book or tax purposes.

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

A. PGE proposes to treat the 2011 equity issuance fees as a regulatory asset for rate making purposes and amortize them over a 10-year period beginning in 2011, consistent with the treatment provided by the Commission in UE 197. Thus, we have added $1.1 million in equity issuance expense and we have added a regulatory asset to our rate base to reflect the average unamortized balance in 2011. Finally, to recognize the non-tax deductible nature of these fees, we have added a permanent book-tax difference to the derivation of income tax expense in the test year.

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

A. We propose this approach here to smooth the impact of the sizable equity issuance offering expected in 2011 and to better match the recognition of costs with the expected benefits of the capital projects that the equity will help finance.

Q. Is PGE's 2009 equity issuance also reflected in this filing?

A. Yes. We have continued the 10-year amortization of the 2009 equity issuance costs in this case, along with the 2011 projected remaining average unamortized balance based on the Commission's treatment of these costs in UE 197.

VII. Income Taxes, Taxes Other Than Income

A. Income Taxes

Q. What is PGE's 2011 estimate of income taxes?

A. PGE's 2011 test period income tax expense forecast is $65.5 million. PGE Exhibit 306 details the test year calculations of income tax expense and provides a comparison to previously authorized income tax assumptions. This compares to Commission-authorized utility income tax expense of $57.8 million based on approved rates. The increase in 2011 test year income tax expense compared to current rates primarily reflects increased taxable income due to higher rate base, additional requested equity return, and a higher Oregon state tax rate reflected in this case, offset partially by the effect of additional federal tax credits related to Biglow Canyon phase 3.

Q. What methodology did you use to establish estimated income tax expense for the 2011 test year?

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

Q. Does SB 408 (or OAR 860-022-0041) impact your estimate of income taxes for this case?

A. No. SB 408 requires an annual true-up between taxes collected and taxes paid, as those terms are defined in the statute and OAR 860-022-0041. SB 408 itself does not require that test year rate making assumptions about income taxes be changed. For PGE in particular, it does not make sense to attempt to derive test year income tax expense using anything other than the stand-alone approach because PGE's non-utility activity is minimal.

In order to implement SB 408, certain ratios must be established based on rate case results to derive taxes collected for purposes of SB 408.

Q. Have you calculated the updated ratios for SB 408 reflecting PGE's proposed revenue requirement in this case?

A. Yes. The updated net to gross ratio and effective tax rate to be used for SB 408 purposes in 2011 are shown in our work papers.

Q. What income taxes does PGE pay?

A. PGE pays income taxes to the federal government, States of Oregon and Montana, 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 7.60%, and the State of Montana marginal tax rate is 6.75%. The State of Oregon tax rate has increased from 6.60% to 7.60% as a result of legislation passed in 2009, and approved by voters in a January 2010 ballot referendum.

Q. What is PGE's state composite tax rate for this filing?

A. PGE's composite state tax rate is 6.24%. 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 197?

A. Yes. In UE 197, the state composite tax rate was 5.12%. In this proceeding, we have adjusted the figure upward to 6.24% to reflect the higher state tax rate in Oregon, as well as adjustments to the allocation of taxable income between Oregon, Washington, and Montana that reflect 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 39.06%. 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% + 6.24% - (35.00% * 6.24%) = 39.06%

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 and to act as the SB 408 automatic adjustment clause for local income taxes. 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 2011?

A. Yes. We included $3.2 million of state Business Energy Tax Credit (BETC), $0.5 million of non-Independent Spent Fuel Storage Installation (ISFSI) state pollution control tax credits, and $31.1 million of federal NEPA credits in the estimate of 2011 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. As previously mentioned, this filing includes Biglow Canyon phase 3 costs and benefits, including $11.1 million of federal NEPA credits.

Q. Why did you exclude ISFSI state tax credits from the derivation of 2011 income tax expense?

A. ISFSI tax credit amortization is excluded because PGE separately defers ISFSI tax credits pursuant to UM 1186. Since these credits will be refunded to customers separately, we exclude their effects on cost of service in the 2011 test year.

Q. What level of Biglow Canyon project related BETC credits are included in your 2011 test year forecast?

A. We include $2.2 million in BETC credits, all of which relate to phase 1 of the Biglow Canyon project.

Q. Did you include BETC credits related to Biglow Canyon phase 2 or 3 in your 2011 test year forecast?

A. No. The ODOE has recently issued new administrative rules governing the eligibility of renewable energy projects to receive BETC credits. At this time, the interpretation and application of the rules to Biglow Canyon phases 2 and 3 is uncertain. While PGE has received preliminary certification for these BETC credits, we are uncertain if Biglow Canyon phases 2 and 3 will be eligible for these credits. Therefore, we excluded $4.4 million from the 2011 test year.

Q. If it becomes evident during the rate case process that PGE will in fact receive BETC credits for Biglow Canyon phases 2 and 3, will PGE incorporate them in the test year forecast?

A. Yes. If it becomes apparent that either Biglow Canyon phase 2, phase 3, or both will be eligible for BETC credits, PGE will incorporate the credits into the 2011 test year.

B. Taxes Other Than Income & Fees

Q. What is PGE's 2011 estimate of Taxes Other Than Income and Fees?

A. As shown in PGE Exhibit 307, total Taxes Other Than Income are $100.6 million. This compares to 2008 actual costs of $83.4 million. The individual sources of increased costs from the 2008 actuals to the 2011 test year are:

- Franchise Fees: from $36.2 million to $45.6 million;
- Payroll Taxes: from $12.0 million to $11.9 million;
- Property Taxes: from $33.8 million to $41.7 million; and
- Other miscellaneous fees: from $1.5 million to $1.4 million.

Franchise Fees

Q. How did PGE estimate franchise fees?

A. We evaluated the expected level of franchise fees based on estimated 2011 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.

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 2.517%, nearly identical to the rate of 2.514% authorized in UE 197.

Q. Why have franchise fees increased between current rates and the 2011 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 a 10.0% 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 are payroll taxes flat between 2008 actuals and the 2011 test year?

A. Payroll taxes are essentially flat between 2008 actuals and the 2011 test year due to the low wage/salary growth between those years described in PGE Exhibit 500 as well as the AMI related FTE reductions.

Property Taxes

Q. Please describe PGE's obligation to pay property taxes?

A. PGE holds property in three states: Oregon, Washington (KB Pipeline for gas used at Beaver), and Montana (Colstrip and related transmission). As a result, PGE pays property taxes in each of those jurisdictions. Each state uses its own method to determine the property tax obligation.

Q. How does PGE estimate property taxes?

A. PGE's estimates property taxes in each state using a highly involved process that reflects the various methodologies employed by the assessing jurisdictions. The complicated nature of the calculation does not lend itself well to using simplified methods, such as a CPI factor, because there are so many factors requiring consideration.

Q. Please explain further.

A. PGE uses a unit approach because our properties are so thoroughly integrated that the summation of valuing each individual property would not equal the entire utility. PGE uses three indicators of value in evaluating utility valuation. In addition, jurisdictions are not required to use historical valuation methodologies, but in the end, the taxing jurisdictions make the final determination.

1. Calculation Methods to Estimate Property Tax

Q. What is the first method PGE uses to valuate utility property?

A. PGE uses the Cost Approach. Value is derived using the regulatory calculation for rate base with adjustments, as follows:

Plant in Service
\+ Construction Work in Progress
\+ Materials and Supplies
\+ Future Use
\+ Contributions in Aid of Construction (CIAC)
<u>- Accumulated Depreciation/Amortization</u>
= Net Value

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 and therefore an addition to the calculation of plant in service.

Q. Are there other adjustments?

A. Yes. The Trojan switchyard is still in use and therefore taxable, despite the fact that PGE's Trojan assets were written off previously for book purposes. In addition, to be in compliance with SFAS No. 143 (Asset Retirement Obligations), any assets included in plant in service or accumulated depreciation for asset retirement obligations are excluded from tax assessment. Lastly, PGE is required to pay reservation fees for wind turbines not yet delivered. All advance payments or deposits for equipment not yet received are excluded from tax assessment.

Q. What is the second method used by PGE to calculate property tax?

A. The second method is the Income Approach. This approach values the utility by the amount of income PGE earns. A prospective buyer would look at the capitalization of the future income stream (cash flow) that PGE could produce via 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 (usually January 1 of any year at 1:00 a.m.).

Q. How is the capitalization rate determined?

A. Cost of capital is the basis of the capitalization rate. In Oregon, PGE's capitalization rate is 9.1% percent and Montana is 7.5% percent for direct capitalization of net operating income. A high capitalization rate would reflect a lower valued property.

Q. What is the third method used by PGE to calculate property tax?

A. The third method is the Sales Comparison approach. This method compares similar properties that have sold recently. Very similar to the market pricing of residential homes – the recent home sales in a neighborhood provide an indicator of the value of residential properties. This approach is somewhat difficult to estimate due to limited sales activity in the utility industry. In place of this, tax authorities estimate value by examining the market value of stock and debt. This approach is also difficult to calculate because of the fluctuating nature of stock prices.

2. Correlation and Allocation

Q. Once these three methods are used to arrive at a valuation, how is property tax estimated for each state?

A. We begin by reviewing the three values and allocate by state. In Oregon, the three methodologies are reviewed by the Department of Revenue and they determine a value based on their judgment. Montana assigns a weight to each method to come up with system value. The weighting process is very subjective. Since we have very little presence in Washington, the three approaches to value are not used. Washington does not determine a system value.

Q. How is the allocation by state determined?

A. System value is allocated to the state in which the property resides. Oregon starts with total system value and then deducts the market value of 'out of state' property. Montana uses the WSATA formula (Western States Association of Tax Administrators). The WSATA allocation factor uses cost, operating capacity, and production megawatt hours by state to estimate a percentage to allocate to Montana. Washington value is the historical cost less depreciation of Washington's assets.

Q. Can PGE negotiate with any of the states?

A. Yes and we do almost every year in Oregon and Montana. Because of the straight-forward valuation methodology in Washington, historically we have not appealed in Washington.

Also, we have very little presence in Washington (17 miles of an 18 mile pipeline), the amount of property taxes is small and it is not cost effective to appeal.

Q. Has PGE benefited by appealing in Oregon and Montana?

A. Yes. In Oregon we achieved a reduction in asset value of approximately $139 million, which results in a $2 million reduction in property taxes. In Montana, PGE achieved a value reduction of $2.8 million. We generally have a difficult time in Montana. Since we have limited property value in Montana as compared to Oregon, the costs to appeal in Montana may not be worth the savings achieved.

3. Estimate of 2011 Property Tax

Q. What is PGE's forecast for 2011 property taxes?

A. PGE's forecast of 2011 property taxes is $41.7 million, an increase from actual 2008 expense of 23%. Because property taxes are usually paid on a fiscal year basis, PGE must forecast two years' of property tax assessment rates in coming up with the 2011 forecast of property tax expense.

Q. Please describe PGE's special tax treatment for Biglow Canyon Wind Farm and Port Westward.

A. PGE was able to negotiate a property tax reduction with Sherman County in exchange for funding certain Sherman County programs. Sherman County agreed to offer PGE a Strategic Investment Program (SIP) benefit which consisted of a partial property tax exemption (also referred to as a "property tax holiday") in lieu of PGE funding Sherman County programs such as the library and schools. The SIP benefit is the difference between the property taxes paid to Sherman County plus the funding to the county programs, less what the property taxes would have been.

Q. Please describe PGE's special tax treatment related to Port Westward.

A. The Enterprise Zone program serves local governments, such as Columbia County, that wish to employ incentives and other assistance available to stimulate business investment and job creation in their communities. The standard enterprise zone exemption abates taxes on new property for three to five years. For Port Westward no property tax will be paid in 2008/2009 through 2012/2013.

Q. What are the primary reasons why property taxes will increase from 2008 to 2011?

A. The estimated property tax expense increase from $33.8 million in 2008 to $41.8 million in 2011 is primarily due to four factors: 1) $4.6 million increase due to Biglow Canyon Wind Farm becoming operational, 2) $1 million increase is attributable to Montana property tax (as our rate base increases so do our Montana property taxes), 3) $1 million due to Selective Water Withdrawal closing to plant in January 2010, and, 4) $1.4 million for increases in tax rates in Oregon, Washington, and Montana and other miscellaneous rate base increases. Our work papers provide the basis for our 2011 property tax estimate and the change from actual rates.

Q. Was the 2011 estimate of Biglow Canyon phase 3 property tax expense developed assuming the Strategic Investment Program (SIP) agreement?

A. Yes. The SIP was approved in December 2007. As a result, we expect property tax expense for 2011 for Biglow Canyon phase 3 of $1.3 million versus estimated $4.8 million without the SIP.

Q. Did you include the SIP-related costs for 2011 funding of programs in Sherman County?

A. Yes. We included $635,000 of program-related cost associated with the SIP to fund programs in Sherman County in 2011. These costs are recorded in A&G accounts, however, rather than as property tax expense. Funded programs include School Renewable Energy Program, Sherman Development League Library, Community Renewable Energy Association, and Sherman County Renewable Energy Projects.

Q. Does your 2011 forecast of property tax expense assume a property tax holiday for Port Westward?

A. Yes, for 2011 we anticipate $2.4 million property tax savings associated with the Port Westward generating facility located within the Enterprise Zone.

VIII. Capital Expenditures

Q. What are PGE's total 2011 capital expenditures?

A. As shown in PGE Exhibit 308 and summarized in Table 7 below, PGE forecasts $364 million in total utility capital expenditures for 2011, compared with 2008 actual capital expenditures of $371 million.

Table 7
(Capital Expenditures in $Millions)

Type	2008 Actual	2011 Test Year
Production	$17.2	$23.2
Transmission	5.1	4.6
Distribution	117.4	138.8
Intangible	7.4	5.1
General	24.0	27.3
Cap Ex – Operations	171.1	199.0
Strategic	199.5	165.1
Cap Ex – Total	**$370.6**	**$364.1**

Q. How does PGE account for capital expenditures?

A. As PGE spends capital for utility projects, we record it as CWIP, a non-rate base account. Once the project is completed, PGE moves the capital expenditures (and associated AFDC) from CWIP to plant in service accounts. Once moved to plant in-service accounts, the project becomes part of PGE's rate base with associated depreciation expense and property tax expense recorded in the appropriate income statement accounts.

Q. Are there any significant capital expenditures that you do not expect will close to plant in service during 2011?

A. Yes. We forecast capital expenditures for the Cascade Crossing transmission project that we currently expect to close beyond the end of 2011. In addition, we forecast capital expenditures for our proposed capacity and energy projects in the IRP that will also close beyond the test year. Our work papers detail the capital expenditures in 2010 and 2011 that are expected to close in 2011 (or prior) as well as those capital expenditures that are expected to close after 2011.

IX. Rate Base

Q. What is PGE's 2011 average rate base and what does it include?

A. The total 2011 average rate base is $3,244 million. PGE Exhibit 309 provides the details of the 2011 average rate base, which includes PGE's investment in plant in service, net of Accumulated Depreciation, Accumulated Deferred Taxes, and Accumulated Investment Tax Credits (ITC). In addition, the average rate base includes Fuel and Materials Inventory, Miscellaneous Deferred Debits and Credits, and Working Cash.

Q. How does PGE's 2011 rate base compare to rate base amounts approved (or pending) in prior dockets?

A. PGE Exhibit 310 shows that the average rate base approved/pending in prior dockets is $2,706 million. PGE's average rate base increases by $538 million to $3,244 million, as a result of several factors. The major factors include:

- The completion of Biglow Canyon phase 3, increasing rate base by $379 million;
- The receipt of a new FERC license to operate the Clackamas hydro projects, increasing rate base by $64 million;
- The completion in 2010 and inclusion in 2011 rate base of AMI increases average rate base by $64 million;
- The completion of low NOx burners at Boardman, increasing average rate base by $14 million;
- An efficiency upgrade of the Coyote facility, increasing average rate base by $17 million;
- Closure of certain Information Technology (IT) system replacement program conform with increasing rate base by $15 million;

- New regulatory debits for equity issuance fees and pension financing costs in 2011, increasing average rate base by $21 million;
- Reduced working capital needs lowering average rate base by $11 million; and
- Miscellaneous other changes, including depreciation of prior vintage plant in service, capital additions, deferred tax changes, and other changes decreasing rate base by $24 million.

Q. How did you develop the estimate of plant in service for the 2011 test year?

A. First, we estimated year-end 2009 embedded plant using actual results as of the end of the third quarter with forecasted closings through year-end. Next, we evaluated 2010 and 2011 capital additions. Certain larger projects were closed based on a specific forecasted closing date. For example, we forecast the Clackamas relicensing project to close by December 31, 2010. Also, we expect the low NOx burners at Boardman and the Coyote turbine upgrade to close in June 2011 and May 2011, respectively, corresponding to the end of the maintenance outages at Boardman and Coyote.

However, we model most capital additions by evaluating CWIP balances using historical experience. We then applied a forecast closing pattern to CWIP to develop plant in service estimates from 2010 and 2011 capital additions. Our work papers detail the development of 2011 plant in service from forecast embedded plant at year-end 2011.

Q. Are there any new rate base items in 2011 relative to prior proceedings?

A. Yes. We have two new deferred debit balances in the 2011 test year. The first is deferred 2011 equity issuance costs, which average $10 million for the 2011 test year. The second is incremental pension funding costs above the level of pension expense in 2011, which average $11 million for the 2011 test year.

Q. Do you have any other observations regarding 2011 rate base?

A. Yes. The overall growth in PGE's rate base relative to either authorized amounts in current rates or forecasted year-end 2009 balances is the result of the specific investments described above. PGE's capital additions related to operations are generally designed to maintain the existing system and are at a rough steady-state with annual book depreciation.

Q. Does PGE propose a new lead-lag study to update working cash in 2011?

A. Yes. PGE completed a new lead-lag study, a summary of which is provided as PGE Exhibit 311, and the study results are provided in our workpapers. The result is a working cash allowance figure of 3.90% for 2011 as compared to the 5.20% figure used in UE 197.

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

A. Applying the 3.90% working cash factor to the total forecast operating expenses in 2011 of $1,563 million yields the working cash addition to rate base of $61 million, which is shown in PGE Exhibit 301.

Q. Does the lead-lag study take into account the cost of collateral deposits described in PGE Exhibit 1100?

A. No. With regard to purchased power and fuel, the lead-lag study evaluates the lag between delivery month of fuel or power and the payment of an invoice. It does not capture the financing costs associated with movements in the value of an energy/fuel position prior to the month of delivery, which is the basis of collateral requirements described in PGE Exhibit 1100.

X. Biglow Canyon phase 3

Q. Please summarize the revenue requirement of PGE's Biglow Canyon phase 3 investment.

A. PGE is requesting recovery of approximately $29.0 million of revenue requirement for the 2011 test year, which is a component of the overall revenue requirement provided in PGE Exhibit 301. In a separate filing under the Renewables Adjustment Clause (RAC), PGE will also request deferral of Biglow Canyon phase 3's 2010 revenue requirement. These amounts are net of the estimated value of the energy produced by Biglow Canyon phase 3.

A. Project Description

Q. Please provide an overall description of the Biglow Canyon Wind Farm.

A. Biglow Canyon is located in Sherman County, near the Columbia River in north-central Oregon, and is being developed in three phases. Biglow Canyon phase 1 is complete, consisting of 76 wind turbines, each with a capacity of 1.65 MW, for a total capacity of approximately 125 MW. Biglow Canyon phase 1 has been operating since late 2007 (see Docket No. UE 188). Biglow Canyon phase 2 is also complete, consisting of 65 wind turbines, each with a capacity of 2.3 MW, for a total Biglow Canyon phase 2 capacity of approximately 150 MW. Biglow Canyon phase 2 has been operating since mid-2009 (see Docket No. UE 209).

We have begun construction of Biglow Canyon phase 3, putting in roads, foundations, etc. Biglow Canyon phase 3 will consist of 76 turbines, each with a capacity of 2.3 MW, for a total Biglow Canyon phase 3 capacity of approximately 175 MW. We expect to complete Biglow Canyon phase 3 by the end of 2010. In total, the three phases of the Biglow Canyon Wind Farm will have a capacity of approximately 450 MW.

1. Turbine Supply

Q. Who is supplying the turbines for Biglow Canyon phase 3?

A. PGE is using the same model of turbines for Biglow Canyon phase 3 as were used for Biglow Canyon phase 2. Siemens Wind Generation, Inc. (Siemens) is supplying the turbines, pursuant to the Wind Turbine Generator and Tower Supply, Installation, Commission and Warranty Agreement (Turbine Supply Agreement) between Siemens and PGE.

Q. How did PGE select the turbines for Biglow phases 2 and 3?

A. PGE initiated an invitation to bid for Biglow phases 2 and 3 on March 8, 2007, and received bids from several different manufacturers. We narrowed the list of bidders and began negotiations with the remaining bidders. We determined that Siemens provided the best solution for our requirements.

Q. Why did PGE select Siemens?

A. PGE selected Siemens based on a set of criteria (e.g., price, ability to meet PGE's timetable, ability to meet turbine order quantity, etc.). Additionally, PGE wanted to acquire larger turbines for phase 2 and/or 3 than the 1.65 MW turbines used for Biglow Canyon phase 1 in order to realize the full capacity of the Biglow Canyon wind farm site.

Q. What is the warranty period?

A. Under the Turbine Supply Agreement, Siemens will perform warranty service for a period of five years, which includes the initial warranty period of two years and a three-year extension.

Q. What did PGE pay for this three-year extension?

A. The guaranteed availability and warranty extension of three years was at an incremental cost of approximately $8.8 million. During the invitation to bid process, PGE sought bids with approximately a five-year warranty period. This will provide PGE a period of time when only Biglow Canyon phase 1 will be out of the warranty period, allowing PGE to gain experience in self-providing the services previously covered by warranty. This time period is of greater importance due to the change in turbine vendors.

2. Transmission

Q. Is Biglow Canyon phase 3 in BPA's system control area?

A. Yes. All three phases are in the BPA control area.

Q. Will PGE's Large Generator Interconnection Agreement (LGIA) with the BPA be sufficient for Biglow Canyon phase 3?

A. Yes. On September 11, 2009, BPA issued an amendment increasing the LGIA from 400 to 450 megawatts.

Q. Please describe Biglow's interconnection with the regional grid.

A. To facilitate the interconnection of Biglow Canyon, BPA expanded its 500 kV John Day substation, constructed a new 230 kV John Day substation, and built a new 230 kV transmission line, including a six-mile portion from Biglow Canyon to John Day.

Q. Will BPA provide transmission of power from Biglow to PGE's service territory?

A. Yes. For Biglow Canyon phase 1, we redirected 150 MW of our Rocky Reach to Portland rights under our point-to-point (PTP) transmission agreement with BPA. PGE has redirected 300 MW of our John Day to Portland rights for Biglow Canyon phases 2 and 3.

Q. Do PGE's payments for BPA transmission services change with this PTP redirection?

A. Yes. BPA classifies approximately $15 million of the interconnection costs discussed above as network upgrades. PGE paid for the upgrades to BPA's network and BPA must repay the $15 million, plus interest. Pursuant to the LGIA, BPA will base the repayment credits on MWs of installed capacity. With the addition of approximately 175 MW of capacity, PGE will recover its investment more quickly. We have included an estimate of amortization as well as the BPA credit associated with Biglow Canyon phase 3 in this proceeding.

B. Revenue Requirement

Q. What is the overall impact of Biglow Canyon phase 3 on PGE's 2011 revenue requirement?

A. PGE currently forecasts Biglow Canyon phase 3's 2011 net revenue requirement to be approximately $29.0 million. The 2011 energy benefits, which are included in PGE's 2011 Net Variable Power Cost forecast, are approximately $22.3 million. These benefits are net of the costs to shape and integrate Biglow's variable energy output which are also included in PGE's 2011 NVPC forecast in this filing. PGE Exhibit 312 summarizes the development of Biglow Canyon phase 3's revenue requirement.

Biglow Canyon phase 3's pre-tax operating income is $26.4 million. Depreciation is $18.7 million, O&M costs are $3.9 million, property taxes are $1.3 million[4], revenue sensitive costs total $1.0 million, and net variable power cost benefits of $22.3 million. The result is an overall (net) revenue requirement of $29.0 million.

Q. How do you calculate the net energy benefits?

---

[4] Property taxes are calculated based on MW of nameplate capacity. For Biglow 3 this translates into approximately $2.68 million on an annual basis ($15,340 per MWh times 174.8 MW). Only half of this amount is included for the 2011 test year because the property tax year begins July 1, 2011 and ends June 30, 2012. PGE had zero property tax assessed for the period of July 1, 2010 through June 30, 2011 because there was no operating asset to assess as of January 1, 2010.

A. For purposes of the 2011 revenue requirement, we use the output from PGE's power cost forecasting model, MONET. These 2011 net energy benefits are included in PGE's 2011 NVPC forecast in this filing. From the value of Biglow's output, we then subtract the associated regulation, imbalance, integration, reserve, and royalty costs. We describe these costs in detail later in this section of our testimony.

Q. Will the Energy Trust of Oregon (ETO) provide funding to cover the difference between the cost of Biglow Canyon phase 3's power output and the cost of the same power output purchased at expected market prices?

A. No. Senate Bill 838, The Renewable Energy Act, limits the ETO's ability to fund new renewable resources to projects of up to 20 megawatts. This differs from Biglow Canyon phase 1, where an agreement was reached with the ETO prior to the passage of Senate Bill 838.

1. O&M Costs

Q. Does the 2011 O&M forecast include the cost of a turbine maintenance agreement?

A. Yes. The 2011 cost of the Service and Maintenance Agreement (Maintenance Agreement) is the largest component of O&M for Biglow Canyon phase 3.

Q. Is PGE proposing a major maintenance accrual for Biglow similar to that for Coyote Springs?

A. No. Biglow Canyon phase 3's Maintenance Agreement has a more levelized annual cost, eliminating the need for an accrual.

Q. How many full-time equivalent (FTE) employees will work at Biglow?

A. Currently, Biglow Canyon phases 1 and 2 have six FTEs. We expect Biglow Canyon phase 3 to add two FTEs, consisting of two full-time wind technicians.

Q. How are royalty costs calculated?

A. PGE pays royalties to Orion Energy, LLP (Orion) and the land owners at the Biglow Canyon Wind Farm site on a $/MWh basis. Royalties for 2011 are approximately $2.40 per MWh for Biglow Canyon phase 1, approximately $3.29 per MWh for Biglow Canyon phase 2, and approximately $3.34 per MWh for Biglow Canyon phase 3.

2. Wind Integration

Q. How must PGE manage the intermittent nature of the wind power generated by Biglow?

A. Conceptually, there are three distinct services that PGE must either purchase or self-provide:

1) Within-Hour Balancing, which consists of *regulating margin* (the moment-to-moment adjustments in generation output) and *load following* (the larger step-changes in generation over the course of the hour and during generator ramping);

2) Generation Imbalance, which covers the deviations in output between hourly schedules and actual hourly output; and

3) Day-Ahead and Hour-Ahead Uncertainty, which covers the system optimization costs on a day-ahead and hour-ahead basis.

Q. Which of these services can be purchased from BPA?

A. BPA charges PGE the Wind Integration - Within-Hour Balancing Service and Generation Imbalance Service rates based upon the provisions in PGE's Large Generator Interconnection Agreement. As a Generator Owner/Operator within the BPA Balancing Authority Area, PGE is required to submit day-ahead and hour-ahead generation schedules to BPA for Biglow Canyon. These estimated generation schedules are the basis for the Generation Imbalance Service charges.

Q. How have you modeled regulation, imbalance, and integration costs in the MONET estimate of net variable power costs?

A. PGE used its best estimate of the cost to purchase and self-provide these services during the 2011 test year. Our estimate is based on figures provided in regional discussions, the knowledge of PGE's real time and structuring groups, and BPA's charges for the imbalance and integration services. This is the same approach used for Biglow Canyon phases 1 and 2.

Q. Do you incorporate the cost of operating reserves?

A. Yes. Though not an itemized cost, PGE has updated the operating reserves calculation in MONET to reflect the need to support Biglow Canyon phase 3.

3. Taxes

Q. Are there tax credits associated with Biglow Canyon phase 3?

A. Yes. We include Production Tax Credits (PTC) of $11.1 million in the 2011 test year. These credits are incorporated into PGE Exhibit 312 as 'Federal Tax Credits.'

Q. What are the key features of the renewable energy tax credit?

A. The Emergency Economic Stabilization Act (HR 1424) of 2008 extended the National Energy Policy Act (NEPA) tax credits for renewable energy resources, including a one-year extension of the PTC for wind resources and an eight-year extension of the ITC for solar projects. In February 2009, the American Recovery and Reinvestment Act (Reinvestment Act) further extended the PTCs for wind by three years, through December 31, 2012. The Reinvestment Act also provides the option of claiming a 30% ITC instead of the PTCs. Should a taxpayer claim the ITC, the Reinvestment Act allows for the ITC to be exchanged for an equivalent grant from the Treasury Department.

Q. Did PGE evaluate the Reinvestment Act to determine if any additional benefits are available that would reduce Biglow Canyon phase 3's costs?

A. Yes. As previously mentioned, the Reinvestment Act provides an option to select between production tax credits, investment tax credits, or Treasury grants. Based on our review, the PTCs result in the greatest value to our customers because the ITCs and Treasury grants would be subject to IRS normalization requirements. As a result of these requirements, shareholders (rather than customers) would benefit from the amortization of the ITC/grants, thereby diminishing their value to customers. The revenue requirement provided in this testimony includes PTCs for Biglow Canyon phase 3.

Q. What value do the PTCs provide for customers?

A. Tax credits based on Biglow's production will begin when the plant becomes operational and will continue for 10 years. We estimate $22/MWh in our 2011 revenue requirement. If appropriate, we will incorporate any change to the PTCs in our final test year estimate in this proceeding.

Q. Will Biglow Canyon phase 3 receive Business BETC?

A. Possibly. In November 2009, the Oregon Department of Energy (ODOE) issued temporary rules regarding facilities that qualify for BETC credits that put into question whether or not PGE will receive BETC credits for Biglow Canyon phase 3. As a result, PGE has excluded them from the 2011 revenue requirement. If PGE receives clarification during this proceeding, PGE will include the BETC credits in its forecasts.

Q. Does Biglow Canyon phase 3's average rate base include unutilized tax credits?

A. Yes, in the amount of $11.1 million for 2011. PGE does not expect to have enough taxable income to make use of the entirety of the tax credits associated with Biglow Canyon phase

3, so the deferred tax credits have been added to rate base. PGE expects to use these credits in the future and will amortize them from rate base as they are used.

Q. Does Biglow Canyon qualify for special property tax treatment?

A. Yes. In November 2007, PGE, Sherman County, and the State of Oregon reached an agreement that applies to up to 450 MW of the Biglow Canyon wind farm. In lieu of normal property taxes, PGE pays taxes on the basis of installed megawatts at the project plus specified additional contributions to county projects such as a library, community college, etc.

Q. Does PGE plan to update estimates of Biglow costs and benefits during this proceeding?

A. Yes, for a number of reasons. First, the value of the expected energy from the Biglow project will change as the expected market price of electricity changes and/or as the project begins generating. Second, as the project proceeds through the construction phase, PGE will have better estimates of the total construction costs of the project. Third, if PGE confirms that it will receive BETCs, we will update the 2011 revenue requirement accordingly. For these reasons, we believe updating Biglow's expected revenue requirement is appropriate.

Q. Has the Commission already issued orders to allow the development of the Biglow Canyon wind farm?

A. Yes. Commission Order No. 06-293 (UP 234) allowed PGE to grant a lien to Orion, the original developer of the site, on certain substation property and allowed Orion the right to repurchase certain assets from PGE, if PGE decides not to fully develop the project. Order No. 06-419 (LC 33) allowed PGE to "seek inclusion of the acquisition of the Biglow Wind Project in its rate base at cost, rather than in its revenue requirement at market price" (Order at 1). Order No. 07-573 (UE 188) allowed PGE to recover its costs and earn a return on its investment in Biglow Canyon 1. In Order No. 08-246 (LC 43) the Commission, though not acknowledging the entirety of PGE's 2007 Integrated Resource Plan, did find PGE's renewable resource actions reasonable, which includes the development of Biglow Canyon phases 2 and 3. In Order No. 09-398 (UE 209), the Commission approved recovery of PGE's investment in Biglow Canyon phase 2.

XI. Unbundling

Q. Have you unbundled the 2011 revenue requirement pursuant to OAR 860-038-0200?

A. Yes. PGE Exhibit 313 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 8 below summarizes the unbundled revenue requirement for 2011.

Table 8
(Unbundled Revenue Requirement - $Millions)

Production	$1,189.3
Transmission	36.5
Distribution	487.3
Metering	5.1
Billing	27.7
Other Consumer Services	59.7
Ancillary Services	5.3
Public Purposes	Collected by separate tariff
Total	**$1,811.0**

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

Q. How did you develop the revenue requirement after unbundling costs and rate base?

A. We used traditional revenue requirement methodology – recovery of cost plus a return on rate base – to calculate the revenue requirement for each unbundled service in accordance with OAR 860-038-0200(9)(d).

Q. How did you unbundle PGE's 2011 expenses and other revenue?

A. We unbundled expenses and other revenue by analyzing each ledger within those categories. First, we determined which ledgers could be directly assigned to one of the functional categories listed in Table 8 above. Second, we evaluated those ledgers that could not be clearly assigned to determine a basis for allocation.

Q. Were most of the expense and other revenue ledgers assigned or allocated?

A. The majority of ledgers have a direct relationship with a single functional area and we assigned these ledgers 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, payroll taxes, and income taxes, relate to factors such as net plant, labor, net income, or total revenue. 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 to the ledgers assigned to retail. Second, while we forecast labor costs in non-utility, "below-the-line" accounts, these ledgers already receive allocations for corporate governance (i.e., A&G/Support costs) and service providers (i.e., facilities, IT, and print/mail services). Therefore, unbundling A&G (or other support costs) to non-utility ledgers 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 a ledger-by-ledger basis and directly assigned where applicable (e.g., fuel inventories were assigned to Production). For other categories, we allocated costs on an appropriate basis (e.g., deferred credits related to post-retirement medical and life insurance are allocated based on labor).

Q. Did you assign franchise fees to the Distribution function?

A. Yes. Pursuant to OAR 860-038-0200(9)(c)(B)(i)(IV), PGE assigned franchise fees directly to the Distribution function. We also assigned OPUC fees and writeoffs for uncollectibles directly to the distribution function.

XII. 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 in 1976. I received a Master of Arts degree in Economics from the University of Tennessee in 1993 and a Ph.D. in Economics from the University of Tennessee in 1995. 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. Tinker, please state your educational background and experience.

A. I received a Bachelor of Science degree in Finance and Economics from Portland State University in 1993 and a Master of Science degree in Economics from Portland State University in 1995. In 1999, I obtained the Chartered Financial Analyst (CFA) designation. I have worked in the Rates and Regulatory Affairs department since 1996.

Q. Does this complete your testimony?

A. Yes.

List of Exhibits

PGE Exhibit 301
2011 Results of Operations
Increase in Base Rates Needed for Reasonable Return
Dollars in (000s)

	2011 Results At 2009/2010* Base Rates	Change for Reasonable Return	2011 Results After Change for Reasonable Return
	(1)	(2)	(3)
Operating Revenues			
Sales to Consumers (Rev. Req.)	1,685,812	125,185	1,810,997
Sales for Resale	-	-	-
Other Operating Revenues	20,961	-	20,961
Total Operating Revenues	1,706,773	125,185	1,831,958
Operation & Maintenance			
Net Variable Power Cost	747,192	-	747,192
Operations O&M	220,013	-	220,013
Support O&M	196,147	1,105	197,251
Total Operation & Maintenance	1,163,351	1,105	1,164,456
Depreciation & Amortization	232,564	-	232,564
Other Taxes / Franchise Fee	97,494	3,151	100,645
Income Taxes	18,239	47,208	65,447
Total Oper. Expenses & Taxes	1,511,649	51,463	1,563,112
Utility Operating Income	195,125	73,721	268,846
Rate of Return	6.019%		8.289%
Return on Equity	5.962%		10.500%

* 2009 Rates per approved UE 197; 2010 approved UE 189/204/208/209

PGE Exhibit 301
2011 Results of Operations
Increase in Base Rates Needed for Reasonable Return
Dollars in (000s)

	2011 Results At 2009/2010* Base Rates	Change for Reasonable Return	2011 Results After Change for Reasonable Return
	(1)	(2)	(3)
Average Rate Base			
Plant in Service	6,491,337	-	6,491,337
Accumulated Depreciation	(3,023,949)	-	(3,023,949)
Accumulated Def. Income Taxes	(353,967)	-	(353,967)
Accumulated Def. Inv. Tax Credit	(5)	-	(5)
Net Utility Plant	3,113,416	-	3,113,416
Misc Deferred Debits	47,251	-	47,251
Operating Materials & Fuel	72,169	-	72,169
Misc. Deferred Credits	(50,196)	-	(50,196)
Working Cash	58,954	2,007	60,961
Total Average Rate Base	3,241,594	2,007	3,243,601
Income Tax Calculations			
Book Revenues	1,706,773	125,185	1,831,958
Book Expenses	1,493,410	4,256	1,497,665
Interest Rate Base @ Weighted Cost of Debt	98,496	61	98,557
Production Deduction	-	-	-
Permanent Sch M Differences	(18,342)	-	(18,342)
Temporary Sch M Differences	166,877	-	166,877
State Taxable Income	(33,667)	120,868	87,201
State Income Tax	(5,800)	7,544	1,744
Federal Taxable Income	(27,867)	113,324	85,457
Fed Income Tax	(40,890)	39,663	(1,227)
Deferred Taxes	64,930	-	64,930
ITC Amort	-	-	-
Total Income Tax	18,239	47,208	65,447

Table of Contents

I. Introduction

Q. Please state your names and positions with PGE.

A. My name is Mike Niman. My position at PGE is Manager, Financial Analysis. I provide my qualifications at the end of this testimony.

My name is Terri Peschka. I am the General Manager of Power Operations at PGE. I am responsible for managing PGE's net variable power costs (NVPC). My qualifications appear at the end of this testimony.

My name is Patrick G. Hager. I am the Manager of Regulatory Affairs at PGE. My qualifications appear at the end of PGE Exhibit 1100.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to provide the initial General Rate Case (GRC) forecast of PGE's 2011 net variable power costs and compare this estimate with the 2010 Annual Update Tariff (AUT) NVPC as approved by the Commission in Order No. 09-433 (Docket No. UE 208). We discuss updates to the 2010 AUT parameters such as forward curves, as well as modeling changes, which can occur only in GRC proceedings. We also explain why per-unit NVPC have decreased by $1.63 per MWh from 2010 to 2011.

Q. Are there minimum filing requirements that accompany the GRC and AUT filings?

A. Yes. Order No. 08-505 mandated a list of minimum filing requirements (MFRs) for PGE in future AUT filings and general rate case proceedings. The MFRs define the documents PGE will provide in conjunction with the NVPC portion of PGE's initial (direct case) and update filings of its GRC and/or AUT proceedings. PGE Exhibit 401 contains the list of required documents as approved by Order No. 08-505. The required MFRs are included as part of our electronic work papers, with the remainder of the MFRs to be filed within fifteen days of this filing.

Q. Has producing the MFR documents been helpful to power cost proceedings?

A. Yes. Production of the MFR documentation in conjunction with filings has led to a more transparent process with fewer data requests.

Q. What is your GRC net variable power cost estimate?

A. Our 2011 GRC forecast is $747.2 million, based on forward curves and contracts as of December 17, 2009.

Q. How do you organize the remainder of your testimony?

A. Our testimony has four sections beyond this introduction:

- Section II: Monet Model;
- Section III: Monet Updates and Model Changes;
- Section IV: Comparison with the 2010 UE 208 NVPC Forecast; and
- Section V: Qualifications.

II. Monet Model

Q. How did PGE model its NVPC for the 2011 test year?

A. We used our power cost forecasting model, called "MONET" (or Monet).

Q. Please briefly describe Monet.

A. We built this model in the mid-1990s and have since incorporated several refinements. In brief, Monet models the hourly dispatch of our generating units. Using data inputs, such as forecasted load and forward electric and gas curves, the model minimizes power costs by economically dispatching plants and making market purchases and sales.

To do this, the model employs the following data inputs:

- Forecasted retail loads, on an hourly basis;
- Physical and financial contract and market fuel (coal, natural gas, and oil) commodity and transportation costs;
- Thermal plants, with forced outage rates and scheduled maintenance outage days, maximum operating capabilities, heat rates, operating constraints, and any variable operating and maintenance costs (although not part of net variable power costs for ratemaking purposes);
- 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. Any plant 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.

Q. What is the source of the forward curves that PGE inputs to Monet?

A. For this initial filing, we use a single day snapshot of trading curves to obtain forecasts for 2011 of natural gas prices at Sumas, Rockies, AECO, and Malin, and monthly on- and off-peak power prices at the Mid-C. The trading curves are supplied by PGE's Power Operations Group, which purchases and sells wholesale electricity and gas, and validated by our Risk Management group. For our final update filing in November 2010, we will use a five-day average of trading curves.

Using this forecast, we create hourly wholesale prices for electric power. To create hourly prices, we begin with typical price profiles for winter, summer, and off-season, and for weekdays, Saturdays, and Sundays, and use historical hourly price information. Because we model on-peak prices as independent from off-peak prices in a given month, we review price transitions from on-peak to off-peak hours to make sure they are appropriate. We also examine hourly prices for a typical weekday, Saturday, and Sunday for each month in the forecast period to make sure the prices are consistent between hours (e.g., Sunday prices lower than Saturday prices on-peak). Hourly calculations take into account the number of on-peak and off-peak hours in each month of the forecast period to ensure hourly prices are consistent with the monthly prices. The results of this calculation are used directly in Monet.

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 variable power costs to FERC accounts 501, 547, 555, 565, and 447. Based on prior Commission decisions, we include some fixed power costs, such as excise taxes and transportation charges, because they relate to fuel used to produce electricity. We "amortize" these fuel-related costs even though, for purposes of FERC accounting, they appear in a balance sheet account (FERC 151). We also exclude some variable power costs, such as variable operation and maintenance costs, because they are already included elsewhere in PGE's accounting. However, variable O&M is used to determine the economic dispatch of our thermal plants. The "net" in NVPC refers to net of forecasted wholesale sales of electricity, natural gas, fuel and associated financial instruments.

III. Monet Updates and Model Changes

Q. Does the NVPC section of this proceeding substitute for a 2011 test year AUT 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 allowed only in a general rate case. The final NVPC update in this proceeding will be the 2011 forecast that we will compare with the 2011 actual NVPC under the provisions of Schedule 126, which implements our Power Cost Adjustment Mechanism (PCAM). PGE discusses its proposed revisions to the PCAM in PGE Exhibits 200 and 1100.

Q. What load forecast do you use in this initial filing?

A. We use the 2011 forecast for cost of service load described in PGE Exhibit 1400. That forecast is approximately 19,944,650 MWh, or 2,277 MWa[1], a decrease of 13 MWa from UE 208 (2010 test year).

Q. What schedule in this docket do you propose for NVPC updates?

A. We propose the following schedule for the power cost updates:

- April 1 – update thermal plant parameters and forced outage rates; update power, fuel, and transportation/transmission contracts; gas and electric forward curves; planned thermal and hydro maintenance outages; loads; and any errata corrections to our February 16 initial filing;
- July – update power, fuel, transportation/transmission contracts, and related costs; gas and electric forward curves; planned thermal and hydro maintenance outages; and loads;

[1] This is at the bus-bar and differs from load at the customer meter by line losses.

- September – update power, fuel, transportation/transmission contracts, and related costs; gas and electric forward curves; planned hydro maintenance outages; and loads; and
- November – two updates: 1) forward curve updates, final updates of power contracts, fuel contracts, transportation/transmission contracts, long-term opt outs, and related costs; and 2) final gas and electric forward curves.

Q. What updates and model changes do you propose in this docket?

A. In this initial filing, we include nearly all of the typical updates included in an April 1 AUT filing. One exception is the thermal forced outage rates. We plan to file an update that includes forced outages rates based on 2006-2009 data by April 1, 2010, consistent with information that would be used in an AUT filing for 2011. By this date, we will have processed the 2009 data needed to complete the outage rate calculations. In this initial filing, we use the same forced outage rates based on 2005-2008 data as we used in UE 208 (2010 AUT). In addition, for some items that we update annually, such as 4-year average calculations for certain long-term contracts or fixed coal cost items, we will update these in our April 1 filing. We will also update several of the items included under Schedule 125 as this docket proceeds. Finally, we made the following additional updates and modeling changes in our initial Monet runs:

- Inclusion of Biglow Canyon phase 3 net power cost benefits;
- Updates to reflect the latest Pacific Northwest Coordination Agreement (PNCA) Headwater Benefits study;
- Updated hydro plant H/K factors;
- Add Oak Grove Relicensing Update for Harriet Lake Base Flow;

- Inclusion of mercury control chemical costs at the Boardman plant;
- Reclassification of certain operating costs to net variable power cost including the cost of:
    - Broker fees related with PGE's activities in the gas and electric markets;
    - Credit facilities and margin interest associated with collateral deposits;
    - Ammonia for NOx control at Coyote and Port Westward; and
    - Lime at Colstrip 3 and 4 for SO_2 control;
- Updated Colstrip 3 and 4 to "non-cycling" from "cycling;"
- Improve the modeling of the Coyote Springs auxiliary boiler economics in the dispatch logic;
- Inclusion of a peak/super-peak energy contract; and
- Inclusion of WECC-proposed operating reserves.

PGE will include the following updates in its April 1 filing:

- Coyote Springs Turbine Upgrade; and
- Pelton/Round Butte generation for the addition of the Selective Water Withdrawal (SWW) facility.

PGE also proposes one additional change to simplify the modeling in Monet:

- Relax the requirement to freeze thermal plant variable O&M costs.

Q. What is the impact of these updates and modeling changes on NVPC relative to the final 2010 AUT forecast?

A. The updates and changes in this initial filing decrease NVPC by approximately $36.9 million. However, several of the items in Monet including broker fees, collateral costs, ammonia costs, and lime costs, are reclassifications of operating expenses to NVPC, rather than changes to our modeling. Aside from these reclassifications, updates and modeling changes decrease NVPC by approximately $42.0 million.

A. Biglow Canyon Phase 3

Q. Did you include any Biglow Canyon (Biglow) phase 3 costs in the 2011 GRC NVPC?

A. Yes. We include costs for BPA tariff integration, royalty payments, an imbalance premium, and a day-ahead forecast error estimate, which total $5.9 million. We also include Biglow Canyon phase 3 in our operating reserve calculations. Additionally, we include the BPA Transmission Credit of $2.8 million associated with Biglow Canyon phase 3.

Q. What impact does Biglow Canyon phase 3 have on 2011 power costs?

A. Biglow Canyon phase 3 reduces 2011 NVPC by approximately $22.3 million. This is the result of lower net market purchases ($24.9 million), lower wheeling costs ($2.8 million), and lower WECC incremental reserves cost ($0.5 million). As we noted above, variable costs for Biglow Canyon phase 3 are approximately $5.9 million. PGE’s confidential work papers include the Monet output files with and without Biglow Canyon phase 3.

B. Pacific Northwest Coordination Agreement Study Update

Q. Please describe the updates you made based on 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 2006-07 Study to the 2008-09 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 our UE 208 hydro inputs to Monet (such as removing PGE Hydro maintenance, changing to continuous mode, and adjusting for end-of-study reservoir content).

Q. What impact do these PNCA-related changes have on your 2011 NVPC forecast?

A. The net impact of updating the PNCA study is a decrease in NVPC of $1.7 million.

C. Hydro Plant Performance

Q. How do the hydro plant performance factor updates affect the Monet forecast?

A. The primary updates are to the H/K factors, which translate hydro flows into electricity generation. The H/K factors for North Fork, Faraday and River Mill were updated to correct for a consistent overstatement of the factors based on 9 recent years of actual flow and generation data. We updated the North Fork factor from 10.18 kW/cfs[2] to 8.64 kW/cfs, resulting in a NVPC increase of approximately $1.8 million. We updated the Faraday factor from 10.00 kW/cfs to 7.68 kW/cfs, resulting in a NVPC increase of approximately $2.6 million. We updated the River Mill factor from 5.60 kW/cfs to 4.90 kW/cfs, resulting in a NVPC increase of approximately $0.8 million.

D. Oak Grove Update for Harriet Lake Base Flow

Q. Please describe this update.

---

[2] cfs = cubic feet per second

A. This update models the hydro generation lost at Oak Grove due to a new base flow requirement at Harriet Lake as part of the Clackamas Relicensing Agreement. Under the Relicensing Agreement, PGE will be required to provide a base flow from Harriet Lake year-round, reducing the flow available to the Oak Grove powerhouse for generation. The base flow requirement was calculated net of existing spill due to high flow conditions. This incremental spill was then used to estimate the lost generation at Oak Grove. The new base flow requirement is expected to begin in September 2011, following a scheduled outage.

Q. How does this requirement affect the 2011 NVPC forecast?

A. The net impact of updating Oak Grove for the Harriet Lake base flow requirement is an increase in NVPC of $0.8 million.

E. Boardman Mercury Control Chemicals

Q. What is the basis for your estimate of Boardman mercury control chemicals?

A. During 2010, PGE will install additional mercury suppressant equipment at the Boardman plant. This suppressant system, which will be fully functional in 2011, utilizes brominated, activated carbon to limit mercury emissions to levels required by the Department of Environmental Quality.

Q. What is the annual cost of these emission control chemicals and is it included in NVPC?

A. PGE forecasts the cost of the chemicals to be approximately $1.9 million. It is appropriate to include these costs in NVPC because chemical cost varies directly with the plant's operation, and when incurred will be accounted for as a fuel cost in FERC account 501.

F. Operating Expense Reclassifications

1. Broker Fees

Q. Why is PGE including broker fees in its forecast of NVPC?

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" for "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 included broker fees in its forecast?

A. PGE has forecast 2011 broker fees using historical actuals as a basis and escalating at 2.5%, the standard rate of inflation in Monet, for expected increases in fee rates. The result is an increase to NVPC of approximately $0.7 million.

Q. Is the inclusion of broker fees allowed under the current Schedule 125 and Schedule 126?

A. Yes. Schedules 125 and 126 allow for the inclusion of the "cost[s] of…hedges, options, and other financial instruments used to serve retail load."

Q. Will broker fees be included in future AUT and PCAM filings?

A. Yes. The factors described above are many of the same dynamic attributes that PGE already updates in its AUT filings, which are subject to the PCAM.

Q. Where were broker fees previously recorded?

A. PGE previously recorded and recovered broker fees as power operations O&M.

Q. Have you included these broker fees anywhere else in this rate case aside from NVPC?

A. No.

2. Collateral Deposits

Q. What costs has PGE included related to collateral deposits?

A. PGE has included the cost of certain revolving credit facilities fees and net margin interest[3]. The revolving credit facilities fees are included for only the portion of PGE's credit facilities used to support power operations. PGE discusses collateral deposits in more detail in PGE Exhibit 1100.

Q. What is the effect of including costs associated with collateral deposits in this forecast?

A. The result is an increase to NVPC of approximately $2.6 million comprised of a $2.0 million increase for revolver fees and a $0.6 million increase for net margin interest.

Q. Will costs associated with collateral deposits be included in future AUT and PCAM filings?

A. Yes. PGE will include an updated forecast of collateral deposits and associated net interest costs in future AUT and PCAM filings.

[3] Depending on market conditions, PGE can find itself in a position of being a net recipient or net depositor of collateral. Therefore, it is possible that PGE could be either a net recipient or net payer of margin interest.

Q. Is the inclusion of collateral deposit costs allowed under the current Schedule 125 and Schedule 126?

A. Yes. Schedules 125 and 126 allow for the inclusion of the "cost[s] of…hedges, options, and other financial instruments used to serve retail load."

3. Ammonia

Q. What is the basis for your calculation of ammonia costs for Port Westward and Coyote Springs?

A. Port Westward and Coyote Springs use ammonia to reduce oxides of nitrogen (NOx) emissions to levels that comply with state and federal requirements. In our Monet forecast, we multiply a forecasted ammonia price by an average ammonia feed rate for each of the plants. The average feed rate is based on PGE's historical experience with ammonia consumption and the fuel heat input to the plants.

Q. Did you use this same approach for ammonia in UE 197, the last general rate case?

A. Not precisely. In UE 197, although the method to calculate the cost was very similar, we included these costs in O&M expenses rather than NVPC. We have subsequently determined that it is more appropriate to classify these costs as NVPC because they vary with gas use by the plant and when incurred are accounted for as a fuel cost in FERC account 501.

Q. Are ammonia costs for Coyote Springs expected to decrease in the future?

A. Yes. During the 2011 major maintenance outage, an upgrade to the dry low NOx combustion system will reduce the NOx output that has to be catalyzed by the ammonia, which in turn will result in significantly reduced consumption of ammonia.

Q. What is the NVPC effect of the ammonia costs?

A. The ammonia costs, which have been reclassified from O&M to NVPC, total approximately $0.5 million, comprised of $0.4 million for Port Westward and $0.1 million for Coyote Springs.

Q. Have you included ammonia costs anywhere else in this case aside from NVPC?

A. No.

4. Lime

Q. What is the basis for your calculation of lime costs for Colstrip Units 3 and 4?

A. Colstrip Units 3 and 4 use lime to reduce sulfur dioxide emissions to levels that comply with state and federal requirements. In our Monet forecast, we unitize the Colstrip forecast for total lime costs based on tons of coal burned, and then multiply by the amount of coal consumed on a monthly basis.

Q. Did you use this same approach for lime in UE 197, the last general rate case?

A. No. In UE 197, PGE estimated lime costs for Colstrip and included them as O&M expenses rather than NVPC. We have subsequently determined that it is more appropriate to classify these costs as NVPC because they vary with coal consumption, and when incurred are accounted for as a fuel cost in FERC account 501.

Q. What is the NVPC effect of the lime costs?

A. The lime costs, which have been reclassified from O&M to NVPC, total approximately $1.3 million.

Q. Have you included these lime costs anywhere else in this case aside from NVPC?

A. No.

G. Colstrip Cycling

Q. Please describe the effect of switching Colstrip Units 3 and 4 from cycling to non-cycling.

A. Recent iterations of Monet have produced results where Colstrip Units 3 and 4 cycle on and off on an hourly basis, which does not reflect the plant's actual operation. This cycling logic is appropriate for a simple-cycle combustion turbine such as Beaver Unit 8, but not a coal plant. Switching Colstrip's designation from cycling to non-cycling will make Monet more consistent with the actual operation of this base load coal plant. Doing so also makes the treatment of Colstrip and Boardman consistent in Monet. There is no NVPC change associated with this modeling change at this time.

H. Coyote Auxiliary Boiler

Q. Why did you change the dispatch modeling of the Coyote Springs auxiliary boiler?

A. Until this update, Monet was cycling the plant off without considering the cost of operating the auxiliary boiler during times when PGE is required to maintain operation of the auxiliary boiler in order to serve PGE's steam customers. Although the costs for the auxiliary boiler were captured in Monet, they were not accounted for in the economic dispatch decision of the plant.

Q. What is the result of altering the dispatch modeling for the Coyote Springs auxiliary boiler?

A. The dispatch decision now accounts for the costs to maintain operation of the auxiliary boiler to serve steam customers when Coyote is not generating power, and thus, the dispatch of the Coyote plant and the corresponding auxiliary boiler dispatch are more economical.

Q. How does this change affect NVPC?

A. This change in dispatch logic results in a small NVPC decrease of approximately $0.1 million.

I. Peak/Super-Peak Energy Contract

Q. Please describe the inclusion of a peak/super-peak energy contract.

A. Each year, PGE conducts a planning process to ensure that it has adequate resources to cover a 1-in-5 load excursion event during the summer months, which have high and particularly volatile prices as the entire western grid peaks. The analysis consists of a comparison between available dispatchable thermal generation, forecasted hydro generation, forecasted wind generation, existing long-term power contracts and the peak forecasted loads under the 1-in-5 planning scenario. As part of this analysis, PGE's traders are asked to make a market assessment of the amount of energy PGE can reliably acquire in the prescheduled and real-time markets. This assessed volume typically represents half of the 500 MW to 700 MW necessary to cover a 1-in-5 planning event, as compared to a 1-in-2 load profile. Because PGE can only rely on the short-term market to cover a limited amount of the 1-in-5 load, PGE typically fills the remaining deficit by entering into a summer peak-shaping transaction for firm generation. The simplest and most cost effective product available in the market is an on-peak for super-peak exchange of physical power, where PGE supplies on-peak power and buys super-peak power at a ratio of 1 to 2. This ratio ensures that the transaction is energy neutral on a daily basis, better matches energy supply with demand and, similarly, avoids the drawback of further market purchases where PGE would have to sell excess power in shoulder hours.

Q. What is the NVPC effect of this contract?

A. PGE forecasts that this contract will increase NVPC by approximately $0.6 million.

Q. What is the premium associated with this type of contract and why is it justified?

A. Based on PGE's experience during 2007 through 2009, this type of contract carries a premium of approximately 10%. This premium has two components: 1) the premium value of energy delivered during the highest hourly load period and 2) a risk premium to compensate the seller of super-peak energy for the risks of entering into a forward sales agreement months in advance of actual delivery.

As mentioned above, PGE's experience has been that it can reliably acquire approximately half of the energy deficit during the period in question. The remaining deficit can either be filled by an on-peak for super-peak exchange as described above, or PGE can reserve its own shapeable generation resources for load excursions and purchase larger portions of block energy. The latter approach is less economically efficient than the peak/super-peak exchanges that PGE enters into.

Q. Will peak/super-peak contracts be included in future AUT and PCAM filings?

A. Yes. PGE will include an updated forecast of these contract costs in future AUT and PCAM filings.

J. WECC Operating Reserves

Q. Please describe the implementation of the new standard on WECC Contingency Reserve Requirements.

A. In April 2008, WECC proposed new standards for operating reserves, which NERC approved on October 29, 2008. The proposed standards are currently awaiting approval by FERC. The proposed standards are for operating reserves of 3% of control area load and 3% of generation, which would replace the current requirement for total operating reserves equal to 7% of thermal generation and 5% of hydro and wind generation. FERC has not indicated when they will issue a decision. The overall effect of the change is an increase in operating reserve requirements for PGE, resulting in a $0.7 million increase to NVPC. Should FERC not approve the proposed standards by October 1, 2010, PGE will adjust our NVPC forecast.

Q. Do you provide further information regarding these model enhancements, new items and major updates?

A. Yes. We provide further explanation and support for these in the MFRs included with our Work Papers.

K. Pending Update: Coyote Springs Turbine Upgrade

Q. Please describe this pending upgrade.

A. In 2011, during the plant's scheduled maintenance outage, PGE plans to upgrade various components at Coyote Springs including a new compressor, turbine rotor, casings, and dry low NOx combustion system. These upgrades are expected to increase the generation capacity of the plant and potentially improve the heat rate. PGE will incorporate projections of the operating benefits, and related costs, in its April 1 filing.

L. Pending Update: Pelton/Round Butte Generation for the Addition of the SWW Facility

Q. Please describe this pending update.

A. This update will model the hydro generation lost at Round Butte under normal operating conditions due to a reduction in head caused by the SWW facility. PGE will incorporate projections of this cost in its April 1 filing. However, we have included supporting documentation for this change in the MFRs filed with this case.

M. Dynamic Variable O&M for Thermal Plants

Q. What is your proposed modeling change to variable O&M in Monet?

A. This change would relax the current requirement that the thermal plant variable O&M costs as modeled in Monet be frozen at the April 1 update filing in a general rate case year and remain frozen until the next general rate case. Instead, certain dynamically modeled adjustments in Monet would be permitted, including:

- Annual escalation for general inflation;
- Dynamically modeled transmission loss costs or savings, which depend on burner-tip fuel prices, which are frequently updated. This currently affects only Port Westward and Colstrip;
- The market price of SO_2 emission allowances. This currently affects only Boardman and Colstrip;
- Updates to the Montana Producer's Tax or Wholesale Energy Transaction Tax. This affects only Colstrip; and
- Updates to the plant emission factors for SO_2, which can change when we have a new coal commodity contract. This practically affects only Boardman.

Q. Why do you want to make this modeling change?

A. The reason is to simplify the modeling and arrive at more accurate dispatch decisions in Monet. Currently, there is an inordinate amount of modeling effort and complexity to freeze the variable O&M in Monet between general rate cases considering the relatively immaterial effect on NVPC. Variable O&M is not included in NVPC but is used in the dispatch decision. This will require a change to Schedule 125, which is reflected in PGE Exhibit 1501.

IV. Comparison with 2010 UE 208 NVPC Forecast

Q. Please restate your initial 2011 GRC NVPC forecast.

A. The initial forecast is $747.2 million including Biglow Canyon phase 3. Without Biglow Canyon phase 3, the forecast is $769.5 million.

Q. How does the 2011 GRC forecast compare with the UE 208 2010 forecast approved in Commission Order No. 09-433?

A. Based on PGE's final updated Monet run for the 2010 test year, the forecast is $784.1 million, or $39.09 per MWh. The 2011 forecast is $747.2 million, or $37.46 per MWh.[4]

Q. What are the primary factors that explain the decrease in the 2011 forecast compared to the 2010 forecast?

A. As Table 1 shows, the approximate $36.9 million decrease is due to several factors.

Table 1
Factors in Power Cost Differences ($Million)

Element	Effect
Hydro Cost and Performance	$14
Coal Cost and Performance	17
Gas Cost and Performance	10
Wind Cost and Performance	-18
Contract and Market Purchases	-51
Fewer Market Purchases for Cost of Service Load Decrease	-6
Other (Net)	-4
Total	**-$37**

We expect less hydro production in 2011 due to the expiration of certain contracts, decreased share of output at Priest Rapids and Wanapum, and, as described above, changes to the H/K factors. This reduced output is offset by more costly market purchases. Coal-generated output is reduced in part due to more maintenance days at Colstrip Unit 3

[4] These calculations are based on bus-bar cost of service load and include the fact that the 2011 load forecast is 13 MWa lower.

and Boardman, while costs increase due to higher fixed and transportation costs at Colstrip as well as higher coal costs at Colstrip and Boardman. The cost of gas-generated production increases due to higher gas commodity costs. The addition of Biglow Canyon phase 3 yields greater output and lower costs per MWh for wind generation. Contract costs and volumes[5] for 2011 are lower than 2010, with the volume made up for by even lower-cost market purchases. Fewer market purchases are necessary due to a 13 MWa decrease in cost-of-service loads from 2010 to 2011.

[5] Contract volumes will increase over the course of the year as PGE fills its open power position.

V. Qualifications

Q. Mr. Niman, please describe your qualifications.

A. I received a Bachelor of Science degree in Mechanical Engineering from Carnegie-Mellon University and a Master of Science degree in Mechanical Engineering from the California Institute of Technology. I am a registered Professional Mechanical Engineer in the state of Oregon.

I have been employed at PGE since 1979 in a variety of positions including: Power Operations Engineer, Mechanical Engineer, Power Analyst, Senior Resource Planner, and Project Manager before entering into my current position as Manager, Financial Analysis in 1999. I am responsible for the economic evaluation and analysis of power supply including power cost forecasting, new resource development, least-cost planning, and avoided cost estimates. The Financial Analysis group supports the Power Operations, Business Decision Support, and Rates & Regulatory Affairs groups within PGE.

Q. Ms. Peschka, please state your educational background and experience.

A. I received a Bachelor of Arts degree in Finance from Portland State University. I have been employed at PGE since 1999 in the following positions: Risk Management Analyst, Manager of Risk Management Reporting & Controls, and my current position General Manager of Power Operations. Before joining PGE, I worked at PacifiCorp from 1980 – 1999 in various retail, wholesale, planning and mergers and acquisition positions. In my current position, I am responsible for managing the Power Operations group that coordinates the NVPC portfolio over the next five years.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
401	Order No. 08-505: Excerpt pertaining to MFRs

Minimum Filing Requirements
July 7, 2008

General

The Minimum Filing Requirements (MFRs) define the documents to be provided by PGE in conjunction with the Net Variable Power Cost (NVPC) portion of the Company's initial (direct case) and update filings of its General Rate Case (GRC) and/or Annual Update Tariff (AUT) proceedings.

The term "Supporting Documents and Work Papers" as used here means the documents used by the persons doing the NVPC forecasting at PGE to develop the final inputs to Monet and the final modeling in Monet for each filing. This may include such items such as contracts, emails, white papers, studies, PGE computer programs, Excel spreadsheets, Word documents, pdf and text files. This will not include intermediate developmental versions of documents that are not used to support the final filing. Documents will be provided electronically where practical.

In cases where systems change or are replaced in the future, such as BookRunner, the MFRs will continue to provide substantially the same information as provided in PGE's 2009 GRC (UE-198).

PGE will take reasonable steps to ensure that the MFRs can be made available to CUB and ICNU at the time of the filing, rather than these parties having to wait for the OPUC to approve the protective order in the case.

Delivery Timing

In either an AUT year (April 1 initial filing) or a GRC year (Feb. 28 initial filing), at a minimum the following portion of the Direct Case Filing MFRs will be delivered with the initial filing:

- Summary Documents (Items 1-6)
- Modeling Enhancements and New Item Inputs (Item 14) – not applicable in AUT year
- Miscellaneous Item 15d - re: Testimony and Exhibits provided on the CD

The remainder of the Direct Case Filing MFRs will be delivered with the initial filing if practical, or no later than fifteen days after the filing (e.g. March 15 in a GRC year, April 15 in an AUT year).

For all update filings, Update Filing MFRs will be delivered with the update filing with the following exception. For the April 1 GRC Update Filing in a GRC year, the delivery of Item 23 will be made with the filing if practical, or no later than fifteen days after the filing (e.g. April 15).

Direct Case Filing

Applicability

- Applies to GRC Initial Filing (e.g. February 28) in a GRC year
- Applies to AUT Initial Filing (i.e. April 1) in a non-GRC year

Summary Documents

1. Monet model for the final step
2. Hourly Diagnostic Reports for the final step
3. Step Log showing NVPC effects of modeling enhancements, modeling changes, addition of new items or removal of items from the prior year rate proceeding (GRC or AUT), and other major updates that PGE believes the parties would want to see identified separately, such as updating the hydro study.
4. Output/Assumptions Summary Report comparable to that provided for the 2009 GRC
5. Executable files, any other files needed to run Monet, and installation instructions
6. Identification of the operating system PGE uses to operate Monet

Supporting Documents and Work Papers for the Following

7. Forward Curve Inputs. Consists of:
   a. Electric curve extract from Trading Floor curve file
   b. Gas curve extract from Trading Floor curve file
   c. Canadian/US Foreign exchange rate (F/X Curve) from Risk Management
   d. Model run for hourly shaping of monthly on/off-peak electric curve (Lydia Program)
   e. Oil forward curve
8. Load Inputs. Consists of:
   a. Monthly load forecast from Load Forecast Group
   b. Hourly load forecast from Load Forecast Group
   c. Copy of the loss study used by Load Forecast Group to develop busbar load forecast
9. Thermal Plant Inputs
   a. Capacities
   b. Heat Rates
   c. Variable O&M

      This includes any other cost or savings components modeled as part of Variable O&M, such as incremental transmission losses, SO_2 emission allowances (emission allowance $/ton price forecast, plant emission factors lb/MMBtu), etc.
   d. Forced outage rates
   e. Maintenance outage schedules and derations
   f. Minimum capacities
   g. Operating constraints
   h. Minimum up times
   i. Minimum down times
   j. Plant testing requirements
   k. Oil usage volumes
   l. Coal commodity costs
   m. Coal transportation costs
   n. Coal fixed fuel costs classified as NVPC items

      Includes items such as: Colstrip Fixed Coal Cost and the following Boardman costs: Rail Car Mileage Tax, Coal Sampling, Rail Car Lease, Rail Car Maintenance, Trainset Storage Fee, and Coal Car Depreciation
10. Hydro Inputs
    a. Monthly energy for all Hydro Resources

       This will include the results of PGE's most current study using the Pacific Northwest Coordination Agreement (PNCA) Headwater Benefit Study. Note that this program is not the property of PGE and should be obtained from the Northwest Power Pool. Provide the PGE version of the PNCA model inputs, so that if the Parties obtain the PNCA model, they would have the inputs needed to reproduce PGE's study.
    b. Description of logic for hourly shaping where applicable
    c. Usable capacities where applicable
    d. Operating constraints modeled
    e. Hydro maintenance derations
    f. Hydro forced outage rates (not currently modeled)
    g. Hydro plant H/K factors
    h. Spreadsheet demonstrating how the hydro energy final output from the PNCA study is adjusted to arrive at the monthly energy output on the PwrAEOut sheet
11. Electric and Gas Contract Inputs
    a. Copy of contract for each long-term (5-year or greater term) or non-standard power contract modeled in Monet.

       For some contracts, this may consist of a term sheet rather than a full contract, depending on what was deemed reasonably necessary by the power modelers to model the contract in Monet.
    b. BookRunner extracts for the test year of:

       Electric Physical Contracts
       Electric Financial Contracts
       Gas Physical Contracts

Gas Financial Contracts
F/X Hedge Contracts

c. Copy of each firm gas transportation or storage contract modeled in Monet
d. List of the PURPA QF contracts modeled in Monet
e. List of the long-term (5-year or greater term) or non-standard contracts modeled in MONET that were not included in PGE's most recent GRC or AUT.
f. Gas transportation input spreadsheet or its successor/equivalent
g. Website snapshots input to the gas transportation spreadsheet
h. Other Supporting Documents and Work Papers for contracts modeled in Monet, including any items showing on the Monet Cost and/or Energy Output reports not covered above. Could include structured contracts, option contracts, etc.
i. Coal contracts: Covered above under Thermal Plant Inputs
j. Amortizations of regulatory assets or liabilities modeled in the Contracts section of Monet

12. Wheeling Inputs
    a. Supporting Documents and Work Papers for all wheeling items modeled in Monet
13. Wind Power Inputs. Includes but not limited to:
    a. Monthly energy
    b. Hourly energy
    c. Maintenance
    d. Forced outage rates
    e. Integration costs, royalties, other costs and elements modeled
14. Modeling Enhancements and New Item Inputs
    a. Supporting Documents and Work Papers for all modeling enhancements and new items modeled in Monet.
    b. Includes modeling or logic changes, changes to the methodology used to compute data inputs or other type of enhancement to the Monet model.
    c. Modeling revisions, refinements, clean-ups etc. that do not affect NVPC under any conditions will not be considered to be modeling enhancements.
15. Miscellaneous
    a. Line Item Adjustments to Monet such as OPUC orders, settlement stipulations, others
    b. Identification of all transactions modeled in Monet that do not produce energy
    c. Items in Monet not covered elsewhere above
    d. For all testimony and exhibits provided on the CD in pdf format, provide the testimony in searchable pdf format, and provide any exhibits created in Excel in the original Excel format when available to PGE.

<u>Historical Operating Data</u>

16. Hourly extract of data from PGE's Power Scheduling and Accounting System showing actual hourly energy values for the most recent Four-Year Calendar Period of the following:
    a. Generation from each coal, gas, hydro and wind generating plant modeled in Monet. Note that Colstrip Units 3 and 4 generation is aggregated in PGE's system, and the Mid-C contract generation is similarly aggregated.
    b. Long-term (>5 years) electric contract purchases, sales and exchanges modeled in Monet.
17. Table showing the actual monthly generation of each PGE coal, gas, hydro and wind generating plant modeled in MONET, from the period 1998 through the last calendar year.
18. Monthly compilations of actual NVPC produced by PGE for the most recent calendar year.

Update Filings

19. Monet model for the final step
20. Hourly Diagnostic Reports for the final step
21. Step Log showing effect on NVPC of each update step since the last filing
22. Output/Assumptions Summary Report comparable to that provided for the 2009 GRC
23. For each Monet update step:
    a. Text description of update, including identification and location of input changes within Monet.
    b. Excel file containing Monet standard output reports (PwrCsOut, PwrAEOut, PwrEnOut) and PC Input sheets.
    c. Supporting Documents and Work Papers for the update step
24. For all testimony and exhibits provided on the CD in pdf format, provide the testimony in searchable pdf format, and provide any exhibits created in Excel in the original Excel format when available to PGE.

Table of Contents

I. Introduction

Q. Please state your name and position with PGE.

A. My name is Arleen Barnett. My position is Vice President, Administration. My responsibilities include establishing compensation policy and employee policies, improving the work environment, overseeing safety and health programs, employee relations, managing employee development, and overseeing Business Continuity and Security. My qualifications are provided at the end of this testimony.

My name is Joyce Bell. My position is Director of Compensation and Benefits in the Human Resources Department. My qualifications are also provided 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 2011 test year and describes significant changes to our compensation policies and plans since 2008. Total compensation costs include base wages and salaries, incentive pay, and employee benefits. We also present and explain PGE's proposal to establish an adjustment mechanism to recover pension expense and financing costs on incremental cash contributions to the pension trust. We then discuss PGE’s changing pension investment strategy, which will limit expense and cash contribution volatility.

Q. What are PGE’s expected total compensation costs in 2011?

A. PGE forecasts approximately $278 million in total compensation costs for 2011, with the increase relative to 2008 driven by the costs of benefits, particularly health related. Table 1 summarizes the costs.

Table 1
Estimated Total Compensation Costs ($Millions)

Component	2008 Actuals	2011 Test Year
Wages & Salaries	191.2	202.9
Incentives	16.1	6.1
Benefits	49.9	69.0
Total Compensation	**257.1**	**278.0**

The increase in wages and salaries since 2008 is primarily due to market-driven wage and salary adjustments ($17.8 million), but is partially offset by FTE reductions ($6.1 million) which are primarily AMI-driven. Test year incentive costs are $6.1 million reflecting application of the Commission's decision in UE 197 to our 2011 incentive costs. Benefits reflect continued cost increases in medical premiums, an increased cost associated with the new defined contribution plan due to the closure of PGE's pension plan in 2009 and renegotiated benefits per the 2009 bargaining agreement.

Q. What is PGE's total compensation philosophy?

A. PGE's philosophy is to provide compensation sufficient to attract and retain employees necessary to provide safe and reliable electric service. 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 does PGE face by following its compensation philosophy?

A. PGE faces three major challenges: 1) recruiting, 2) rising health care costs, and 3) an experienced but aging workforce, which will result in PGE facing significant numbers of retirements.

Q. Please describe PGE's approach to the first challenge – recruiting.

A. PGE faces significant challenges in recruiting and hiring that are common to the industry. In 2009, PGE's major recruiting challenges were in the areas of Finance, Tax, Legal and

Transmission. Despite the current economic environment, the market is very competitive for skilled professionals in those fields and those recruited employees tend to have already been gainfully employed and, in most cases, with long tenure. To fill some of the positions, PGE enlisted the services of contingency-based search firms and offered wages in excess of the mid-point of our pay-guides, in addition to other increased benefits. We expect similar recruiting challenges to continue, and as the economy recovers, we foresee specific challenges in recruiting such skilled positions such as Wireman, Metermen, and Information Technology (IT) Analysts.

Q. How does PGE combat the second challenge – rising health care costs?

A. PGE aggressively negotiates with vendors for favorable terms for provider contracts and outside services. PGE also negotiates and implements plan elements that offer cost efficiencies (one example is a value-based pharmacy plan). PGE performs internal studies to understand which health issues are contributing the most costs. PGE has developed targeted wellness programs designed to reduce long-term costs by lowering employee risk factors. Finally, as health plan costs rise, employees share the increased burden, aligning their interests with PGE's to minimize costs.

Q. Please describe how PGE is planning to meet the third challenge – an aging workforce.

A. Approximately 40% of PGE's workforce will be eligible to retire (at least 55 years of age and five years of service) by the end of 2011. The historical retirement age of a PGE employee has been 60 years. However, due to the effects of the economic downturn, our annual number of employees retiring remains low despite the increasing number of workers eligible to retire. Meanwhile, we continue to recruit and train employees to fill vacancies in critical positions that have a high impact on the organization, have long learning curves, and are hard to fill. Examples of these 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. In addition, as the population of retirement-eligible employees increases, we will continue our workforce development and outreach efforts in K-12 and post-secondary education institutions to develop a future pool of workers.

Q. Have recent economic challenges had an impact on PGE's compensation strategy?

A. Yes. The current economic downturn has presented challenges for many companies. PGE has made difficult decisions regarding compensation, including reducing merit increases, restructuring incentives, and reducing other benefits. These reductions result in PGE's total compensation currently being below market, making recruiting efforts more difficult, and negatively affecting employee morale since there have been no corresponding reductions in workload.

Q. Are these reductions sustainable?

A. No, not in the long run. These reductions were necessary one-time events given the economic environment and its effect on PGE's financial position. It is important for PGE to remain competitive as the economy improves, unemployment declines, and more jobs become available. Employee morale is also an important factor in keeping service and productivity levels high.

II. FTEs and Wages & Salaries

Q. How does PGE calculate its 2011 total wage and salary revenue requirement?

A. Total wages and salaries are a function of the number of full-time equivalents (FTEs) and the market-based pay structure.

Q. Please describe how PGE determines the number of FTEs required for the test year.

A. As part of the annual budgeting process, managers determine the number of labor hours in each position type that are required to accomplish their departments' work. PGE groups positions into 17 categories for exempt employees (excluding officers), 14 categories for non-exempt employees, and one category for union employees. 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 made an adjustment for normal vacancies that occur throughout the year. For historical periods, FTEs are reflective of the actual number of hours worked divided by the number of work hours during that year. Table 2 provides PGE's actual total FTEs (excluding overtime) for 2008 and forecast for 2011.

Table 2
Full-Time Equivalents

PGE FTEs (straight time, unless indicated)	**2008 Actuals**	**2011 Test Year**
Administrative and General	622.7	632.7
Customer Service/Accounts	589.9	472.2
Generation	435.8	455.7
Transmission & Distribution	963.5	968.7
Total FTEs	**2,611.9**	**2,529.3**

Q. Why do FTEs decrease from 2008 to 2011?

A. FTEs decrease by 82.7 from 2008 to 2011 due to a significant workforce reduction associated with Advanced Metering Infrastructure, which more than offsets increases in other areas. Below is a summary of the primary FTE changes and references to testimony where they are described in more detail.

- + 10.0 A&G/IT (PGE Exhibits 600 and 1000)
- - 117.7 Customer Service, including the impact of Advanced Metering Infrastructure (PGE Exhibits 300 and 900)
- + 19.9 Generation (PGE Exhibit 700)
- + 5.2 Transmission and Distribution (PGE Exhibit 800)

Adjusting for AMI, 2011 represents an increase of 33.5 FTE, or less than 0.5% annual growth, since 2008. This annual growth rate is well below the 1.45% annual growth rate approved by the Commission in UE 197 (see Order No. 08-601, pgs. 10-11), and is less than the annual rate of growth in customers since 2008.

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. This practice ensures that our current and prospective employees are fairly compensated while costs are controlled. In 2009, we compared our hourly non-union and salaried non-officer positions with the market. The study showed that PGE's wage and salary structure is highly correlated with the market.

PGE reviews market surveys and Bureau of Labor Statistics and takes into account employee merit increases, if appropriate, to estimate the wage escalation factor used to develop the 2011 test year. PGE forecasts a 2.01% annual increase in overall wages and salaries since 2008. Combining required FTEs with wage and salary increases determines PGE's 2011 revenue requirement. Table 3 summarizes total wage and salary costs for 2008 and 2011.

Table 3
Total Wages & Salaries ($000)

PGE Wages & Salaries (straight time)	2008 Actuals	2011 Test Year
Administrative and General	$52,852	$57,221
Customer Accounts	25,843	21,309
Customer Service	7,823	8,567
Generation	32,957	38,419
Transmission & Distribution	70,833	76,637
Trojan Decommissioning	859	753
Total Wages & Salaries	**$191,167**	**$202,906**

Q. Has PGE made any adjustments to arrive at its 2011 FTEs and wages and salaries figures?

A. Yes. To account for vacancies and/or unfilled positions, PGE has removed approximately $8.0 million from its base budget wages and salaries, which translates into an FTE reduction of approximately 99. The figures in Table 2 and Table 3 are net of these reductions.

Q. Did PGE recently renegotiate its contract with the Union including changes in compensation and benefits?

A. Yes. In 2009, PGE completed negotiations with the Union and initiated a new Collective Bargaining Agreement (CBA) that is effective beginning March 2009 through February 2012. The CBA establishes a level of compensation for bargaining employees including wages, medical and retirement benefits which are competitive and approximate the 50th percentile of the market.

Q. What portion of PGE's wages and salaries does the Union represent?

A. The Union represents approximately 30% of PGE's wages and salaries.

Q. Did PGE freeze wages in 2009?

A. Yes. Given the financial pressures on PGE and its customers, PGE decided to place a hold on exempt employees' salary increases (including officers), other than increases for certain high performing employees who were paid significantly below market (excluding officers).

Q. Does PGE intend to continue to freeze wages in 2010 and/or 2011?

A. No. As a result of the wage freeze in 2009, employees' salaries are now below the market reference point. This reduces PGE's ability to retain these employees and makes attracting new employees more challenging, as they could do the same job elsewhere for higher wages. Turnover in 2009 was down slightly, which reflects the impact of economic conditions on retirements and job prospects. However, maintaining or expanding this deficit by freezing wages again would begin to severely hamper PGE's ability to attract and retain qualified employees as the economy recovers and job opportunities expand.

III. Incentives

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. PGE monitors the employment market and acquires information regarding incentive compensation program design practices. Even though it is a small part of PGE's total compensation, incentive pay allows PGE to remain competitive in the labor market while encouraging 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. Incentive pay was approximately 6.3% of PGE's 2008 total compensation, but is only 2.2% of PGE's 2011 total compensation. Table 4 provides detailed actuals for 2008 and forecast for 2011.

Table 4
Total Incentives ($000)

Incentives Component	2008 Actuals	2011 Test Year
Performance Incentive Compensation	5,232	3,330
Annual Cash Incentive	7,281	2,026
Stock (long-term incentive plan)	2,177	647
Notables and Miscellaneous	1,401	135
Total Incentives	**16,091**	**6,138**

Q. Have there been any changes to PGE's incentive plans?

A. Yes. PGE changed both the Corporate Incentive Program (CIP) and the Annual Cash Incentive (ACI) plans for employees to further align goals with customer interests. The Performance Incentive Compensation (PIC) plan replaced the CIP. The structure of the two plans now have a higher performance bar, have a greater emphasis on operational efficiency and process improvements that add value to our customers and shareholders, and are described in more detail below.

Q. Why was this change necessary?

A. It is important that PGE's incentive plans directly support PGE's strategic direction, our commitment to our core principles, continuous improvement, and performance advancement. Improvements in efficiency and process benefit both customers and shareholders. PGE has made the goals of the new incentive plans more difficult to achieve, 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 maintain a competitive stock price and access to capital. Copies of the new incentive plans are included in our work papers.

Q. Please explain how the PIC plan aligns employee performance measures with customer interests.

A. PGE aligned its PIC plan with customer interests by basing the incentive pool on two customer-focused goals:

- Individual or Team Performance: These individually determined goals encourage growth, development, and alignment with corporate operational goals (e.g., efficiency, operational standards). Actual award amounts will be based on employees' incentive targets and their performance achieving Scorecard results.
- Financial Performance: Financial strength can reduce customer rates through lower borrowing costs and, thus, lower cost of capital. This portion of the plan will only be funded if financial goals are met.

Q. Did the incentive plans for Biglow, Port Westward, and Coyote Springs also change?

A. Yes. They have been updated since 2007 and continue to motivate employees to pursue efficiencies and a high level of operations at the respective plants.

Q. Please explain how the ACI plan aligns 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 together and then factored with the final goal of Net Income.

- 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 overall revenue generated for each retail customer group, respectively.
- System Reliability: This goal is measured using 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 goals must be met at their targets to trigger a payout for SAIDI.

- Generation Availability: General plant availability influences power costs. In the long-term, if we further reduce forced outage rates, power costs should also decline.
- Net Income: As mentioned above, financial strength can reduce customer rates through lower borrowing costs and, thus, a lower cost of capital.

Weighting for the first three categories and the potential percentage of payout vary by position level and individual.

Q. Please describe PGE's long-term incentive program.

A. PGE initiated its stock incentive plan in 2006 and it reflects market practice; many publicly traded companies provide stock incentives to promote performance and retention of directors, officers, and key employees. PGE's stock incentive awards are earned and paid out after several years. The Commission approved this stock issuance and accurately 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" (OPUC Order No. 06-356, p.1). PGE forecasts approximately $0.7 million for the 2011 total stock incentive expense.

Q. Does PGE have other programs that reward employees' exceptional performance?

A. Yes. Notable Achievement Awards (Notables) and miscellaneous awards are given to employees on a case-by-case basis for exceptional performance. Notables are promptly distributed to recognize employees' outstanding work on a specific project or task. PGE's 2011 forecast for Notables is $125,000. PGE forecasts $10,100 for miscellaneous awards in 2011 that are also available for managers to distribute on a case-by-case basis when performance is extraordinary, but does not fit within the Notable framework.

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 2011 test year.

Q. Did you exclude a portion of incentive plan costs from this case?

A. Yes, we incorporated an adjustment to remove 100% of the cost of officer incentives (ACI and stock incentives) and 50% of the cost of incentives for all other employees. This adjustment is reflected in Table 4.

Q. Why did PGE make this adjustment?

A. We are making this adjustment in this rate case 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 this adjustment in this filing, we still believe that these costs are appropriate to be included in customer prices in the future.

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, and PGE and the market. As with the other two compensation components (wages/salaries and incentives), PGE compares our benefits programs to the market and targets prevailing market attributes. PGE also uses market information to create innovative program designs to provide greater employee choice and improve our ability to control costs. As a result, we believe that our total compensation package is sufficient to attract and retain quality employees.

Q. What components comprise PGE's total benefits?

A. There are four major components: health and wellness, post-retirement, disability and life insurance, and miscellaneous benefits. These components are typical parts of our competitor companies' offerings. As shown in Table 5 below, PGE's total benefits costs are expected to increase 11.5% annually from 2008, driven primarily by health and pension costs. We project 2011 employee benefit costs of $69.0 million.

Table 5
Total Benefits ($000)

Benefits Compensation Component	2008 Actuals	2011 Test Year
Health and Wellness	29,806	41,030
Disability and Life Insurance	1,934	3,134
Post-Retirement	16,909	23,712
Miscellaneous Benefits	571	731
Benefits Administration	635	413
Total Benefits	**49,853**	**69,019**

Q. Have there been any changes to PGE's retirement plans?

A. Yes. Beginning February 1, 2009, PGE closed its pension plan to new participants. Employees who are hired after February 1 participate in the new defined contribution plan.

This new plan allows for a dollar-for-dollar employer match for the first 5% that a participant contributes to his 401(k) plan. The company will also contribute an additional 5%. Thus, an employee could potentially see as much as 10% contributed to his 401(k) by PGE each year, if they contribute at least 5% on their own. The closure of the pension plan did not impact employees at the Coyote or Port Westward facilities, whose continuing participation in the pension plan is subject to negotiation.

Q. Why did PGE make this change?

A. FAS 158 requires PGE to include the market value of the pension plan assets on its balance sheet, which introduces significant volatility to PGE's financials. The Pension Protection Act also increases the volatility of pension funding and generates new funding requirements that increase net income volatility. (The direct implications of these changes are discussed further in Section V below.) As a result, we asked Hewitt Associates (Hewitt), a Human Resources consulting firm, to prepare a study on retirement plan redesign. After review, we decided to close the pension plan and shift new employees to the new defined contribution plan. The new plan is aligned with the shift from defined benefit to defined contribution plans that is occurring in today's market, in local utilities and other industries.

Q. How is PGE trying to mitigate increases in benefit costs?

A. PGE works hard to keep benefit costs down through programs that encourage a healthy workforce, modifying benefits plan structures to track market practice, and negotiating for favorable contract terms. For example, we implemented an innovative value-based pharmacy design with Providence in 2009 that reduced premiums and reimburses participants more for chronic conditions, which are one of the major drivers of healthcare costs. The goal is ongoing and thorough treatment, which leads to lower costs in critical care or emergencies. The annual premium savings associated with value-based pharmacy are approximately $0.2 million. As chronic conditions are brought under control, PGE's future medical premiums will be lower than they would be without such a program. PGE has also worked to reduce outside fees by streamlining the quantity of analyses that our consultants perform and by renegotiating vendor contracts. Additionally, when health care premiums do rise, PGE shares the cost increases with employees.

PGE also adjusts program features to help control costs. As discussed above, PGE closed its pension plan and transitioned to a new defined contribution plan, which minimizes the pension plan's long-term risk to customers by reducing their exposure to market volatility. We also introduced the value-based pharmacy (mentioned above). For PGE's union employees, we were able to change their plan from a Base Major Medical plan to a Comprehensive Preferred Provider plan during negotiations in 2009, which utilizes preventative medicine and cost sharing to help contain costs in the future.

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 for persons identified as high risk during our health screenings to lower their medical risks (e.g., diabetes, heart disease, high cholesterol, high blood pressure, etc.). PGE's medical vendors provide and encourage participation in wellness programs and disease management programs for our employees. These programs help reduce major medical events which impact our medical premiums. Increased awareness and case management results in fewer medical events and claims, which results in lower future premiums.

Q. Medical and dental benefits costs increased approximately $11 million from 2008. What causes the increase in these costs?

A. Nationally, medical and dental costs continue to rise each year. PGE strives to keep those increases as low as possible. 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.

Table 6
Non-bargaining Medical & Dental Premium (% change)

	2008	2009	2010	2011 (2)
Kaiser Medical	10.40%	3.90%	11.10%	8.60%
Kaiser Dental	2.40%	3.20%	5.70%	8.60%
Providence(1)	6.5-12.40%	6.9-12.20%	2.7-3.60%	8.60%
MetLife Dental	-2.00%	1.70%	4.80%	8.60%

(1) Providence has 4 different plans. The changes above are ranges amongst the 4 plans.
(2) 2011 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 12% annually based on a semi-annual survey of local insurance companies' annual claims cost trend rates performed by Mercer. These rates are used by the insurance companies to project their insured renewal rates.

Q. What Health and Wellness expenses are included in the 2011 test year?

A. PGE forecasts approximately $0.5 million for health and wellness costs in 2011. PGE strives for a healthy workforce, and its wellness programs, which are in line with the Oregon Governor's wellness initiative in 2008[1], 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, team building and productivity. Such programs include Energy for Life and the AfterHours Program. Energy for Life health programs include biometric testing, health risk appraisals, professional health coaching, obesity management, health club reimbursements and disease prevention. The AfterHours

[1] http://governor.oregon.gov/Gov/P2008/press_103108.shtml

program provides partial reimbursements to employees who engage in programs that promote social engagement and healthy lifestyles. Also included is occupational health services, which provides flu shots, health screening, and case management.

Q. PGE's benefits programs use "flex dollars." How do flex dollars work?

A. PGE allocates flex dollars to eligible non-bargaining employees each pay period. Employees use these flex dollars to help pay for medical, dental, vision, employee life insurance and accidental death and dismemberment (AD&D) premiums.

Q. How do PGE's health plan costs compare to market benchmarks?

A. PGE's costs are at or below market benchmarks. Towers Watson (formerly Towers Perrin) reports the results of a survey of health care plan costs incurred by various employers and PGE's reported non-bargaining medical care costs in the 2009 study are slightly below that of the Electric/Utilities Industry. An analysis of the composition of participants (age, gender, family size, etc.) in PGE's plans was included as part of this study in order to create a benchmark incorporating the survey data, adjusted to reflect the costs of a population comparable to PGE's. PGE's costs per non-bargaining employee fall 6% below the cost per employee of this benchmark.

Q. What is PGE's targeted cost-sharing ratio?

A. PGE targets an overall cost-sharing ratio of 85% company and 15% employee for non-union medical, dental and vision premiums; this ratio is reflected in the quantity of flex dollars employees receive. Employees then pay the remainder of the costs. Per the 2009 Energy Services BENVAL Study, a comparison of benefit values among peer utilities with similar revenues, also prepared by Towers Watson, PGE is at the industry average for its share of overall benefit program costs.

Q. Please explain PGE's 2011 disability and life insurance benefit forecast of $3.1 million.

A. PGE's disability and life insurance benefits are comprised of union short-term disability insurance, long-term disability insurance, and retiree group life insurance for all employees.

PGE forecasts union short-term disability insurance costs of approximately $457,000 in 2011. This is relatively flat compared to 2008, representing a decrease of less than 1%. PGE successfully negotiated a competitive union short-term disability contract that renews annually. Costs for 2010 and 2011 appropriately reflect current claims history. PGE's non-union short-term disability expense is included as a payroll labor loading, and is not included in the short-term disability forecast.

PGE forecasts long-term disability costs for bargaining and non-bargaining employees to be approximately $1.6 million in 2011. PGE relies on a forecast by Towers Watson (Towers), an outside 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 applied, the health care trend assumptions used, the number of participants, and the demographics of the participant population. The expense in a given year is calculated as the difference between the ending and beginning liabilities, plus the benefits actually paid by PGE in that year. PGE pays 85% of the health care benefits for non-union employees and 90% for union employees on long-term disability.

PGE forecasts retiree group life insurance costs to be approximately $1.04 million in 2011. The discount rate used by Towers is based on a high quality bond benchmark and was reduced in 2009 from 6.75% to 6.25%. This change results in increased annual contributions because investments are expected to grow at a slower rate. For bargaining employees, PGE pays for a level of coverage for life insurance for retiree members. Active 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[2].

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 not in the defined benefit plan. These costs change with base wage and salary levels and employee participation. Employees represented under the main bargaining contract participate in either PGE's pension program or the RSP but not both. From 2008 to 2011, costs associated with the RSP are expected to increase from $14.6 million to $16.5 million, or approximately 4.1% annually. This increase is primarily a result of a 1% bargained increase to the fixed contribution for the union participants beginning March 3, 2010 (per the 2009 bargaining agreement) and an increase in contributions for new non-union employees in the new RSP plan design discussed above. We discuss pension obligations in Section V below.

PGE forecasts total HRA costs to be approximately $1.4 million in 2011, which represents a 2% annual reduction since 2008. The 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 wages and salaries into a notional account for

[2] 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.

retiree HRA benefits. For bargaining employees, the new CBA provides that, beginning March 4, 2009, PGE's contribution of $0.50 per straight-time hour into the HRA account will be diverted as a contribution into the employees' RSP. This amount will increase to $1.00 per straight-time hour beginning effective November 2011 in lieu of an additional wage increase.

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 2011 cost for miscellaneous employee benefits?

A. PGE forecasts 2011 costs for miscellaneous benefits to be approximately $0.7 million. Miscellaneous benefits are additional 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: $453,340 – 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 and classes that enhance technical knowledge. This program increases the availability of qualified employees to fill open positions. Career development is also a prime recruiting tool and source of employee motivation and satisfaction, which also aids retention.

- Service Awards: $225,000 – As a retention and morale improvement strategy, PGE honors employees for their years of service at five-year anniversary intervals. PGE has historically been considerably under market in the awards provided.

Q. Why do PGE's Benefits Administration costs decrease from $635,000 in 2008 to $413,000 in 2011?

A. PGE has diligently worked to reduce costs and was able to reduce costs for consultants and outside vendors by renegotiating contracts and decreasing the scope of work of consultants.

V. Pension

Q. Please describe PGE's defined benefit pension plan.

A. PGE sponsors a non-contributory, defined benefit pension plan, of which substantially all participants are current or former PGE employees. As of December 4, 2009, the plan had approximately 4,450 participants, of which approximately 1,850 are active non-union, 700 are active union, and 1,900 are retirees. Eligible individuals vest after 5 years of service and accrue benefits based on a number of factors, including years of service and final average earnings. PGE's pension benefit obligation is expected to continue to increase over the next several years as remaining eligible employees vest.

Q. Has PGE taken any actions to limit its pension benefit obligation?

A. Yes. As discussed previously, effective February 1, 2009, new non-bargaining employees are ineligible for the pension plan. Though the near-term effect is minimal, closing the plan will reduce PGE's 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 Financial Accounting Standards (FAS) purposes, PGE's pension plan was 83% funded as of December 31, 2009. This compares to 81% as of December 31, 2008. Second, for Pension Protection Act (PPA) purposes, PGE's pension plan was 86% funded as of December 31, 2009. This compares to 108% as of December 31, 2008. PGE Exhibit 501 shows the pension's FAS 87 funded status, discount rate, investment return, benefit payments, and cash contributions between 1998 and December 31, 2009. PGE's pension plan has been fully funded for most of this period and, as a result, PGE's customers have borne very little pension cost.

Q. What are PGE's projections for expense, cash contributions, and the funded status of the pension plan for the next five years?

A. PGE's third-party actuary, Hewitt Associates, estimated PGE's pension expense and cash contributions for the next five years. Confidential PGE Exhibit 502C contains their estimates as of November 6, 2009.

A. Pension Funding Requirements

1. Pension Expense

Q. How is pension expense calculated?

A. Pension expense, more formally known as "FAS 87 net periodic benefit cost," is comprised of the following components: service cost, interest cost, expected long-term rate of return on assets, amortization of prior service cost, and amortization of net gains or losses.

Q. What assumption does PGE use for its expected long-term rate of return?

A. PGE uses an expected long-term rate of return of 8.50%.

Q. How is PGE's expected long-term rate of return determined?

A. Based on the pension plan's asset allocation, an equivalent portfolio invested in passively managed funds is expected to yield a long-term rate of return of 7.95%. To this we add approximately 55 basis points (net of fees) of additional expected return because the plan is invested in actively managed funds.

Q. What assumption does PGE use for its discount rate?

A. PGE uses a discount rate of 6.5%, which is a market-based forecast of rates of return on long-term high quality (AA rated) bonds.

Q. How sensitive are PGE's pension costs to changes in the long-term rate of return and the discount rate?

A. A 0.25% increase in the expected long-term rate of return on plan assets would decrease PGE's expected 2011 pension expense by approximately $1.2 million. A 0.25% reduction in the discount rate would increase PGE's expected 2011 pension expense by $1.4 million. This sensitivity is exemplified by the plan's 2009 performance where, despite an approximate 26% return on assets, a 100 basis point decline in discount rate outweighs the return - resulting in only a 2% increase in the funded status between 2008 and 2009.

2. Pension Protection Act

Q. Please summarize the requirements of the Pension Protection Act.

A. Signed into law in August 2006, the PPA creates funding percentage requirements for private industry culminating in a requirement of greater than, or equal to, 100% beginning in 2012. In the meantime, funding percentage requirements escalate 2% annually beginning at 90% in 2007. The 2011 percentage funding requirement is 98%.

Q. Does the PPA provide funding options?

A. Yes. The PPA provides two options for funding any shortfall: lump-sum or 7-year amortization.

- A lump-sum contribution would require PGE to make a cash contribution to raise the value of plan assets to the percentage funding requirement. PGE must make an additional cash contribution in an amount equal to Target Normal Cost less any credit balance (we discuss these concepts below).

- The 7-year amortization method allows PGE to make a series of smaller cash contributions over the course of 7 years. The contributions are equal to a 7-year amortization of the difference in the value of plan assets less any credit balance and the percentage funding requirement. PGE must also make a cash contribution in an amount equal to Target Normal Cost less any credit balance.

Q. What is Target Normal Cost?

A. Target Normal Cost (TNC) is the present value of benefits accrued during the year. PGE must make a cash contribution equal to TNC unless one of the following criteria is met:

- The plan is over-funded in an amount greater than or equal to TNC;
- PGE has a credit balance in an amount greater than or equal to TNC; or
- The combination of a credit balance and over-funding is greater than or equal to TNC.

Q. What is a credit balance?

A. A credit balance is created when PGE makes a contribution to the pension plan when one is not required. PGE made such a contribution in 2005 of $10 million. Any such contributions are aggregated and adjusted by the plan's earnings rate and can be used to offset future cash contribution requirements.

Q. Does PGE propose using the 7-year amortization funding option?

A. Yes. Using the 7-year amortization option dramatically reduces the size of the contribution made in the test year, limiting the potential impact to customers. The 7-year amortization option also has the benefit that, if PGE's funded status were to meet or exceed the percentage funding requirement in a subsequent year, then future contributions are no longer required. For example, if 4 years into the 7-year amortization PGE's funded status exceeds the 100% requirement, the remaining 3 years of contributions are no longer required.

Q. Does this amortization period differ from that of FAS 87 net periodic benefit cost?

A. Yes. Pension expense smoothes out pension costs over the remaining life of the plan's participants, which is one of the primary reasons cash contributions differ from FAS 87 expense.

Q. Does PGE use the same assumptions for discount rate and expected long-term rate of return for pension expense and PPA funding requirements?

A. Yes.

Q. Do the assumptions for calculating FAS expense and PPA cash contributions differ?

A. Yes. There are two primary differences, one on the asset side and one on the liability side of the equation. On the asset side, for FAS purposes, PGE must use the market value of the portfolio at December 31. For PPA purposes, PGE has the flexibility to use the market value of the portfolio at December 31 or to look back and choose a period over which to calculate the average balance.

On the liability side, for FAS purposes, PGE must use the discount rate as of December 31. For PPA purposes, PGE has the flexibility to use a month's average or pick a spot rate from the preceding 4 months. For assets and liabilities, the PPA methodology helps smooth market volatility.

Q. Why are these differences important?

A. They help to explain, in addition to the difference in amortization periods, why funded status and expense/contributions can vary considerably, and further justify why an adjustment mechanism is appropriate for recovery of pension related costs.

B. Pension Adjustment Mechanism

Q. Why is the Pension Adjustment Mechanism (PAM) appropriate?

A. The PAM provides PGE the opportunity to recover prudently incurred pension expense and financing costs for cash contributions that are required per the Pension Protection Act, as discussed above. Given the differences between pension expense and PPA cash contributions, and the market volatility the pension plan is exposed to, this mechanism ensures that PGE recovers only its prudently incurred costs.

Q. Please describe the proposed PAM.

A. Similar to the Annual Update Tariff, PGE proposes that the Commission establish a separate tariff for the PAM. This mechanism would include an annual update of rates based on a forecast of future expected pension expense and cash contributions, with new rates effective January 1 of the prospective year. The mechanism would also recover differences between forecast and actual expense, and would update the basis for recovery of financing costs based on actual expense and cash contributions.

Q. Please provide a hypothetical example of how this mechanism would work.

A. We outline the steps below:

- PGE begins by submitting a forecast of pension expense and cash contributions for the test period.
- Subsequent to OPUC approval of the forecast, PGE creates a regulatory asset (“financing basis”) for the difference between cash contributions and pension expense. This balance is the basis for PGE’s financing costs for the test period.
- On January 1 of the test period PGE begins recovering its forecasted pension expense and financing costs.

- During the test period, PGE tracks actual pension expense and cash contributions.
- By October 1 of the test period, which is now the current year, PGE submits an update to the tariff (see PGE Exhibit 1500 and 1501 for pricing and tariff details) for the ensuing year. In this filing, PGE will: 1) detail the difference between forecast and actual pension expense for the current year, 2) provide the amount of actual cash contributions for the current year, and 3) provide a forecast of pension expense and cash contributions for the upcoming year.
- On January 1 of the upcoming year, PGE's prices would include the new pension expense forecast net of the difference between forecast and actual pension expense from the prior period. PGE would also update its financing basis to the actual net cash contribution from the prior period net of the forecasted difference between cash contributions and pension expense.

Q. How is financing basis affected by a general rate case?

A. Between rate cases, the financing basis in the tariff is reduced by the forecasted difference between pension expense and cash contributions from the most recent rate case. At the time of the next general rate case, the financing basis in its entirety, plus the forecast for the test year, will be included in base rates along with the forecast of pension expense (much like this filing). In other words, at the time of a general rate case, the PAM tariff will be reset to zero.

Q. On which interest rate would PGE base its interest costs on?

A. For the interest component of the financing costs, PGE would use its pre-tax cost of capital due to the long-term nature of the underlying costs.

Q. If PGE were granted recovery of only pension expense, wouldn't PGE's pension plan be made whole over time?

A. Not necessarily. First, PGE's pension expense recovery is currently only updated during a general rate case and does not have a true-up mechanism. This leads to variations between what is collected in rates and actual expense in the years between rate cases as well as the test year. Pension expense is expected to vary significantly from year to year over the next several years (see PGE Confidential Exhibit 502C). Second, PGE is subject to considerable financial volatility associated with the earnings of the pension plan, which is exacerbated by the differences between FAS expense and PPA cash contributions. Pension expense is amortized over a much longer period than that of the PPA funding requirements. As a result, contributions that PGE is required to make are likely to vary significantly from pension expense, particularly during years where the pension plan is under-funded for PPA purposes. PPA cash contributions are required, and PGE would have to, for example, issue equity and/or debt to fund the contributions. This would have a detrimental impact on PGE's capital structure and earnings potential due to un-recovered financing costs. Both items will adversely affect PGE's ability to attract necessary capital.

Q. How do PGE's customers benefit from the PAM?

A. As mentioned above, pension expense has a great deal of volatility. Actual pension expense can also vary from forecast for a number of reasons including factors that are out of PGE's control such as the recent market performance and changes in discount rates. The PAM would ensure that PGE's customers are responsible only for PGE's actual expense, which may include reducing costs for customers between rate cases. Further, the PAM is expected to minimize the variation of costs to customers in any given year when compared to either the lump-sum contribution option or only updating expense and financing costs during a general rate case. The PAM also better aligns costs with customer benefits by ensuring recovery of PGE's actual costs. Such costs are part of the total cost of providing customers with safe, reliable electric service.

Q. What is PGE's forecast 2011 pension revenue requirement?

A. We forecast $7.3 million of pension revenue requirement based on $5.8 million of pension expense and $1.3 million of financing costs in 2011 (plus a gross-up for revenue sensitive costs).

C. Pension Investment Strategy

Q. What is the new investment strategy expected to accomplish?

A. As mentioned previously, PGE has taken steps to manage its pension benefit obligation and we propose to better align the pension assets with pension liabilities to minimize volatility in pension expense and cash contributions. This will be accomplished by modifying the pension's asset allocation over a period of years. The goal is to ensure that changes in market performance or discount rates that result in an increase or decrease to the pension benefit obligation also result in a corresponding increase or decrease to the value of pension assets, thereby reducing pension expense and cash contribution volatility.

Q. How is PGE's asset allocation expected to change over time under the new strategy?

A. Pension assets are currently allocated as follows: 39% US Equities, 23% Non-US Equities, 33% Fixed Income, and 5% Private Equities. Over time, PGE would reallocate equity investments into fixed income investments in order to achieve the alignment described above. This alignment can be considered in terms of how much a pension's assets are "matched," or "hedged," against its liabilities. Currently, in PGE's case, pension assets are approximately 18% hedged, which is typical for similar plans. Ultimately, PGE will hedge the majority of the portfolio.

Q. Why is PGE making this change and over what time period?

A. A combination of the PPA requirements and recent market performance has caused many companies, including PGE, to reevaluate their pension investment strategy. PGE believes such a change is in the best interest of both PGE and its customers because it will reduce pension expense and cash contribution volatility, which translates into lower costs for PGE and customers over the long-term. PGE will be looking for market opportunities to change its asset allocation, and is currently evaluating the proper market indicators and benchmarks for determining when and how to reallocate. PGE expects the reallocation to take several years.

Q. What is the effect of changing the asset allocation on pension expense and cash contributions?

A. As we mentioned previously, the effect will be less volatility in pension expense and cash contributions. As PGE reallocates assets from equities to fixed income, the pension plan's expected rate of return is expected to decrease.

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 in 1972 and certification in Human Resources at Portland State University. I have completed coursework toward an MBA in Human Resources at the University of Portland. As Vice President of Administration, I oversee Business Continuity and Security, and Human Resources areas.

I joined PGE in 1978 and have successfully bid and been selected for various positions at PGE. I guided the HR department through the merger with Enron in 1997 and became Vice President in 1998.

Q. Ms. Bell, please summarize your qualifications.

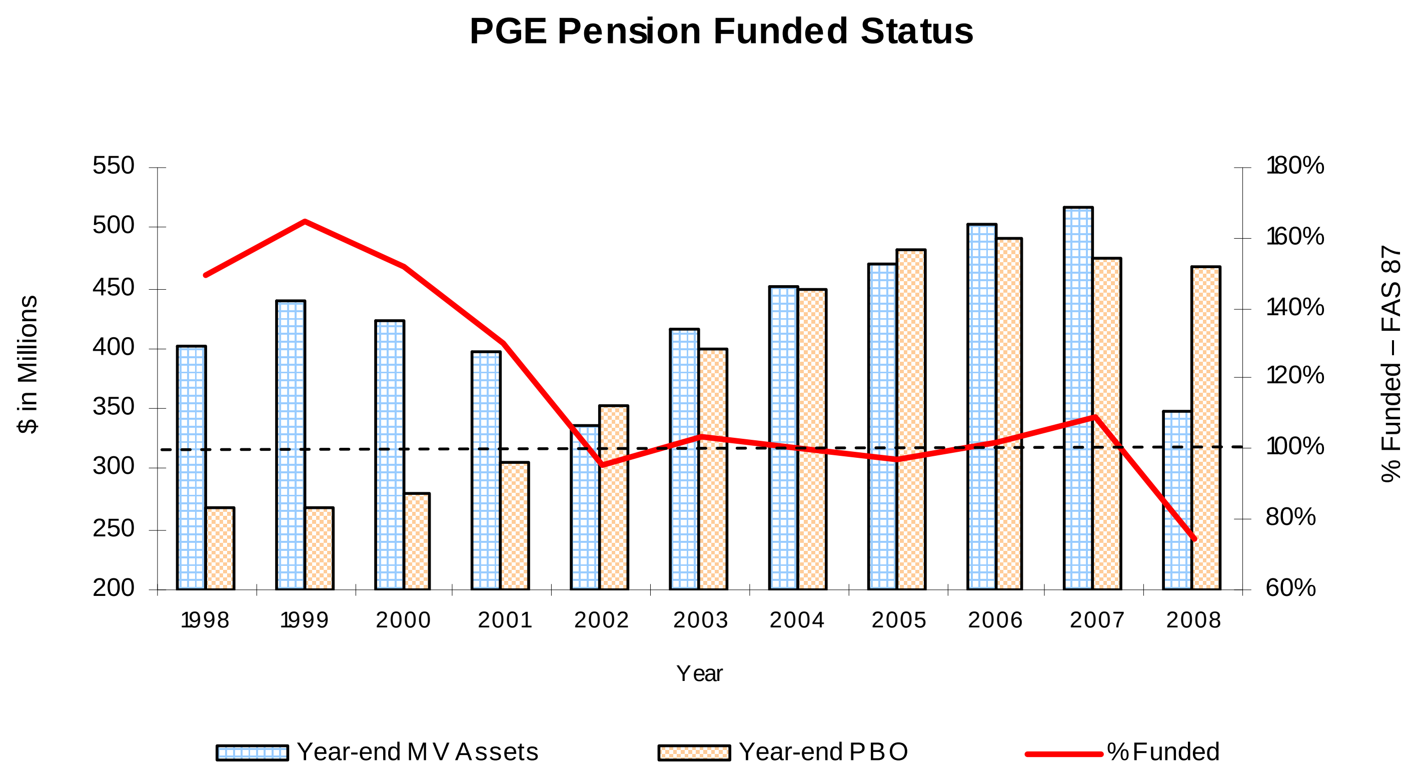
A. I received a Bachelor of Arts degree from the University of Pittsburgh in 1975. I received a Masters in Business Administration from the Joseph M. Katz Graduate School of Business, University of Pittsburgh, in 1976. Prior to joining PGE, I worked at Fireman's Fund Insurance, Co. and American Express in finance; and at Baltimore Gas & Electric Company in the areas of finance and human resources. In 1988, I joined Portland General Electric and I have been Director of Compensation and Benefits since 1998.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Pension Plan Funding Status



	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Discount Rate	6.75%	7.75%	7.75%	7.25%	6.75%	6.25%	5.75%	5.75%	5.75%	6.50%	6.90%	**N/M**
Investment Return	10.41%	18.22%	0.99%	-1.69%	-10.93%	29.78%	11.12%	7.35%	13.59%	8.40%	-28.90%	**4.24%**
Benefit Payments (in millions)	$ 12.3	$ 17.1	$ 17.4	$ 17.0	$ 15.0	$ 17.1	$ 18.5	$ 18.1	$ 24.3	$ 24.8	$ 24.1	**$ 205.7**
Cash Contributions (in millions)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10.0	$ -	$ -	$ -	**$ 10.0**

Portland General Electric

PGE PENSION PLAN FUNDING STATUS

Table of Contents

I. Introduction

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

A. My name is Cam Henderson. I am the Vice President of Information Technology (IT) and Chief Information Officer at PGE. My qualifications appear at the end of this testimony.

My name is Behzad Hosseini. I am the Director of IT Strategy and 2020 Vision. My qualifications also appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. We explain the forecasted increase in costs for PGE's IT department and we describe the changing IT environment that accounts for much of this increase.

Q. What activities or functions are you including as IT?

A. IT consists of PGE departments responsible for developing, operating, and maintaining our computer, cyber, and communication systems. Because these systems are becoming increasingly important to all aspects of PGE's operations (with increasing scope, reliance, and uses) and because the security of these systems is becoming more critical, the demand for IT resources is forecasted to increase significantly in the near future.

Q. How much do you expect operations and maintenance (O&M) costs[1] to increase by the 2011 test year?

A. From 2008 to 2011, we forecast that IT costs will increase from $40.2 million to $54.6 million.[2] We explain the reasons for this increase in more detail below. Because these costs relate to all areas of PGE's operations, they are charged or allocated to appropriate areas and appear as part of each area's O&M costs. Since the majority of those costs relate to

[1] Unless specifically indicated as capital costs, all costs in this testimony refer to O&M costs.
[2] This increase reflects a $2.3 million reduction due to a proposed mechanism related to the 2020 Vision project described in Section IV, Part B, below. Absent this mechanism, IT costs are forecasted to increase to $56.9 million in 2011.

corporate systems, whose costs are allocated rather than charged directly to the operating areas, we discuss IT as a whole in this testimony.

Q. How is your testimony organized?

A. In the next section, we provide an overview of the IT environment that leads to this cost increase. We then provide specific detail regarding the various aspects of the increase. Next, we describe two of PGE's largest IT projects, with costs to be incurred during 2011. The final section provides our qualifications.

II. Overview of the IT Environment

Q. Please provide a brief description of the current environment for IT.

A. Computer information systems have become a critical component of almost every part of a company's operations, and PGE is no exception. Many aspects of our business have come to rely on complex, real-time information that needs to be available 24 hours a day, 365 days a year. Customers have come to expect this as well, and they expect that many of their requests should be handled over the web at <u>their</u> convenience. As the importance of these systems and the dependency of the business on them have grown, so have the security and regulatory requirements. Thus, PGE's IT department has grown significantly and is a much larger part of our operation, as are its costs. IT systems have expanded to almost every PGE operation, expanded their scope, and increased in complexity.

Q. What are some of your more significant challenges moving into 2011 and beyond?

A. The following is a list of some of the challenges we will face in the next few years:

- Increasing Security Requirements – Security and regulatory requirements have increased significantly for the IT department. The nature of online, real-time systems that can be accessed by our customers and suppliers have required stronger solutions in this area. Sarbanes-Oxley, FERC, NERC, WECC, and most recently, the new NERC Critical Infrastructure Protection (CIP) standards have caused us to devote thousands of labor hours within IT to address these requirements, and this trend will continue. We discuss this project in more detail in Section IV, Part A, below (Cyber Security).
- Replacing Old Systems – We have recently initiated a program, which we refer to as "2020 Vision," to replace most of our major information systems over the next

five to six years. As we look at the changes anticipated in our industry over the next ten years and the types of information systems needed to support our operations, we know that most of our IT systems will need to be upgraded or replaced. Even if our business processes do not change, vendor support or technical advancements would require us to make significant investments in these systems. The 2020 Vision strategy involves implementing new systems that will be used across the enterprise wherever possible, in contrast to legacy applications that are typically department-specific. This will reduce the number of systems we have to support, establish common standards and business processes used across the company, better integrate data between systems, and allow us to further reduce the complexity of our IT operations. More importantly, we plan to use this as an opportunity to implement industry “best practices” and improve our business processes to gain further operating efficiencies. We discuss this project in more detail in Section IV, Part B, below.

- New Development and Monitoring Tools – We have invested in WebSphere, Interwoven, Tivoli Identity Management, OpenView, Remedy, and other tools to help us more efficiently develop and maintain systems, implement better system controls, share data across multiple applications, and monitor the operations of our data center. The use of consistent tools and standards across the department enables us to simplify the IT environment and more proactively and consistently manage the IT operations.
- Smart Grid – IT is currently involved in software development for new system processes associated with Advanced Metering Infrastructure (AMI) deployment.

In addition, IT will be a significant factor in implementing customer and system benefits after AMI deployment is complete (see PGE Exhibit 300, Section III).

- Network Connectivity – As our dependency on information systems has grown, the need for data connectivity throughout the company has also grown. In response, we have implemented a microwave and fiber optic ring network connecting all of our major facilities throughout the region. The bandwidth requirements for this network have also grown as we send text, maps, engineering drawings, operating commands, video, and now voice over these connections. Further, PGE's AMI and Energy Management System have added new requirements for redundancy and increased security for our network.
- Increasing Hardware and Software Maintenance – Over the past few years, we have consolidated most software maintenance into the IT budget and the software contracts are managed by our contracts management group. This has not only provided consistency in contract administration, but it has also enabled us to better control our costs. The consolidation has also shifted costs to the IT-specific budget but this change does not affect PGE's overall costs.

Q. How are you addressing these challenges?

A. We are addressing these challenges in a number of ways, including:

- Using a centralized approach to IT
- Reducing the complexity of the IT environment
- Using proven technology
- Applying a preference for packaged application software whenever possible
- Leveraging our investment in software applications across the company

- Using integrated suites of products
- Managing IT as an enterprise asset
- Leveraging web technology

Q. Please describe PGE's centralized approach to IT.

A. A centralized approach means that we concentrate the development, operations, and maintenance of the IT systems within a single functional group rather than allow each operating area to determine its own IT strategy. At PGE, we believe the centralized basis is a more cost effective solution and enables us to leverage investments and skill sets across a wider base. However, some IT operations at our generating plants are more decentralized. We have found that plant management systems are best supported by plant personnel who are responsible for the operation of the plant. Although decentralized, these plants still follow company standards for hardware, software, network connectivity, security, and other standards applicable across the entire company.

Q. How are you reducing the complexity of PGE's IT environment?

A. In the past, many companies, including PGE, followed an IT strategy to select "best of breed" packages, regardless of the hardware platform, the computer language, or what database and operating system they used. As a result, we now support numerous hardware platforms, operating systems, databases, and programming languages. In order to simplify our IT requirements, we have developed a strategy to support three hardware platforms, three operating systems, and two databases. In addition, we are beginning to take steps to reduce the number of programming languages we support. To accomplish this, we are following a strategy of "fewer, deeper vendor relationships." Oracle, IBM and Microsoft are our three primary vendors; each has some areas of unique solutions and sometimes all three offer similar solutions. Competition between these vendors in overlapping areas helps keep our costs down. By using more of their products and services, we found that we have been able to negotiate better prices and build stronger working relationships. These improved relationships lead to tangible benefits of enhanced support and stronger commitment to the success of our operations.

Along with the consolidation of vendors, we have also developed a central group for managing hardware, software, and service contracts. Through consolidated purchasing, better negotiations and consistent monitoring of the contracts, we estimate we have saved more than $1.5 million over the past three years.

Q. Please explain your use of proven technology.

A. Early adopters of technology often pay a premium for new technology or incur additional costs to debug and stabilize new products. As a general rule, we prefer to be a quick follower of new technology once it has been proven to be effective. This allows us to realize the benefits of new technology without incurring additional financial costs or reduced productivity. Examples of this are PGE's adoption of programs for server virtualization, identity management, WebSphere, and voice over internet protocol (VOIP).

Occasionally, because of the deep relationships with some of our vendors described above, we have found it advantageous to work with the vendor to jointly develop some new application features. This may occur when we have a business need that cannot be effectively accommodated with other solutions. In these cases, PGE benefits by having significant involvement from the vendor because it can help reduce our overall costs. Our experience with these types of projects has proven to be very beneficial.

Q. Why do you have a preference for packaged application software?

A. We prefer packaged software rather than custom-developed software for two reasons. First, costs can be lower because software companies recoup their development costs by selling the product to a large number of customers. Second, and more importantly, software companies have an incentive to update their products as the needs of the industry change, making it economical to add the additional functions and features that our customers or regulatory agencies may require.

Given the nature of our business and some of the unique requirements of our customers, there will always be some need for custom development. When this is necessary, we use common IT standards, development tools, and languages to minimize the skill sets required for this work. This allows our development personnel to be able to work on a variety of programs across the business.

Q. What do you mean by leveraging your investment in software applications?

A. By leveraging, we mean that we maximize the use of software products that we purchase. Where different parts of the business have similar information needs, we ask them to evaluate existing products that are already in use to determine if the existing products can meet their requirements. Doing so reduces software acquisition costs as well as the resources needed to support the applications.

Although we have not always done so in the past, our approach to implementing packaged software is to minimize the amount of custom changes we make to the programming code. This allows us to cost-effectively implement upgrades as necessary to take advantage of new features as well as new technologies offered by the vendors. While we may not acquire every version of a program, our intention is to always have a supported version in place. We believe this is an economical way to extend the life of our software investment.

An example of this approach is Masterpiece, the financial system we are currently replacing. It is 26 years old and has been upgraded many times over the years, but now the vendor is phasing out its support. Although it is not likely that PGE will be able to use future systems for two-and-a-half decades, this example demonstrates our philosophy of maximizing the investments we make in software products.

Q. Please explain suites of integrated products.

A. The software market has changed over the past few years as Oracle, IBM, and Microsoft have been very aggressive in acquiring smaller software companies. As a result, they are each building bundled or integrated suites of products, often dedicated to specific industries such as ours. We now have the option of obtaining products that can support a number of different business functions that have the advantage of being built on the same platform using the same tools. More importantly, these vendors are taking responsibility for integrating these various modules, thus reducing the efforts of an individual business to share information between these systems. In addition, these companies work with hardware and database vendors to ensure that their products continue to operate on current, supported technology.

This represents a fundamental change to the IT environment. As we discussed above, in the past, companies bought the best applications they could find and then worked to integrate them together. Now, we can purchase suites that are already integrated.

Q. How are you managing IT as an enterprise asset?

A. In the past, we managed IT resources by line of business. That is, projects were prioritized by the line of business and outside of that department, there was little visibility into the resources committed to implementing or supporting technology. As we have moved toward larger projects and more integrated solutions, we are managing IT as an enterprise-wide resource. Cross-functional teams of managers and officers review requests for IT services and help IT determine priorities for these investments. This helps IT stay aligned with PGE's strategic direction and helps ensure limited IT resources are assigned to the projects that provide the greatest overall benefit to the company.

Q. What are the benefits of leveraging web technology?

A. Web technology provides numerous benefits to our customers. Customer surveys give us high marks for the functionality of our customer websites and the self-service transactions that customers can complete without a PGE representative. We believe this is a cost effective way to enhance customer service. PGE is also successfully using this technology in building the internal systems that employees use to manage their business operation.

Q. Please summarize the most significant aspects of the current IT environment.

A. The most significant aspects are:

- Expanding IT scope as it becomes an increasingly significant part of all of PGE's operating activities;
- Increasing security requirements to protect PGE systems and critical infrastructure; and
- Increasing need to replace PGE's aging software systems with integrated enterprise systems.

III. IT Costs

A. Summary

Q. How are PGE's total IT costs forecasted to change from 2008 to 2011?

A. PGE forecasts that total IT expenses, including incurred charges and loadings will increase from $40.2 million in 2008 to $54.6 million in 2011. These costs consist of the following components:

Table 1
Total IT Costs ($ Millions)

Category	2008 Actuals	2011 Test Year	Variance 2008 - 2011
Direct Charges	13.8	17.7	3.9
Allocated Charges	26.4	40.7	14.3
Labor Adjustment	0.0	(1.5)	(1.5)
2020 Deferral Adjustment	0.0	(2.3)	(2.3)
Total IT	**40.2**	**54.6**	**14.4**

Q. How are IT costs charged to the specific functional areas?

A. As seen in Table 1 above, PGE's IT costs consist of two categories: directly charged and allocated. 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 ledger accounts related to those operations. Other IT work that is performed in the areas of voice, data, network, communications, 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 ledger account and then allocated to the expense ledger accounts of the various functional areas.

Labor charged to the balance sheet has labor loadings applied per PGE's loading and allocation policies, which are submitted annually to the OPUC Staff as an attachment to our Affiliated Interest Report. A summary of IT charges to each operating area by direct charge and allocation is provided as PGE Exhibit 601.

B. Cost Drivers for Incremental IT Costs

Q. What are the reasons for the cost increases from 2008 to 2011 for IT as a whole?

A. The primary drivers of this increase are cyber security; the replacement of aging IT systems; higher annual maintenance costs for software, hardware, and network infrastructure; AMI; and certain labor and labor-related costs.

1. O&M Labor Costs

Q. Do you have any increases associated with new employees?

A. Yes, but only minimally. As discussed in PGE Exhibit 500, we have significantly limited the increase in full time equivalent (FTE) positions as reflected in the 2011 test year forecast. For IT specifically, we forecast an increase of only 8.3 FTEs, which represents a 1.0% annual average increase.

Q. What types of positions do the incremental FTEs represent?

A. We will require three FTEs for the AMI project for application development and communication support. We also need the following FTEs associated with cyber security: critical infrastructure protection analyst, security specialists, and identity management analysts. In addition, we need FTEs for data storage administration and desktop support.

Q. Given the increase in FTEs, what is the total labor increase due to IT activities?

A. The total labor increase from 2008 actuals to the 2011 forecast is approximately $3 million, which also includes payroll escalation over three years for a labor-intensive operation and reinstituting O&M activities that were temporarily deferred for capital jobs. For more detail on PGE's total labor costs, see PGE Exhibit 500.

Q. Please explain the O&M increase associated with reinstituting O&M activities.

A. From 2007 to 2010 PGE used personnel normally involved in O&M activities to supplement AMI and other development work. By 2011, when certain capital jobs will be completed, those employees can shift back to their regular duties, which include:

- A backlog of requested software functionality enhancements to existing applications.
- Lower priority vendor application software upgrades and patches.
- System and software patches to keep our software and operating systems at appropriate version levels to make sure we comply with vendor support agreements.
- Hardware vintage replacement.

Q. Please explain the increase due to labor-related costs.

A. As noted above, IT labor charged to voice, data, network, communications, and office systems that are corporate in nature are first charged to a balance sheet account and then allocated to operating expenses after having labor loadings applied (e.g., employee benefits, incentives, paid time off, and payroll taxes) per PGE's loading and allocation policies. From 2008 to 2011, we forecast these loadings to increase approximately $2.8 million based on increasing labor costs to the corporate IT systems and the overall increase to loaded costs, most significantly employee benefits, which are addressed in PGE Exhibit 500.

2. O&M Non-Labor Costs

Q. What costs are you forecasting for 2011 related to the replacement of old systems?

A. We project that these replacement costs will consist of $3.8 million in development O&M and $1.4 million in ongoing O&M. We discuss these costs and the 2020 Vision program in more detail in Section IV, Part B, below.

Q. Please explain the increase in IT maintenance costs.

A. Not including the maintenance costs discussed below in association with cyber security, IT maintenance costs are forecasted to increase approximately $2.4 million from 2008 to 2011 and consist of the following:

- $230,000 for network maintenance of PGE's telephone and interactive voice response systems used by the Tualatin customer contact center and World Trade Center outage overflow facilities.
- $71,000 for PGE's new Energy Management System.
- $45,000 to perform an upgrade to the Gentran Integration Suite, which is an electronic data interchange (EDI) tool that enables PGE to perform electronic transactions between PGE and transaction partners and is critical to PGE's cash flow. The vendor's software release cycle requires us to upgrade every other year as well as periodic patching of the software.
- $157,000 for maintenance on data storage equipment due to general data growth.
- $1.9 million associated with PGE's software applications including maintenance on new applications, higher rates on existing applications, and increasing scope on certain existing applications. Specific costs on approximately 100 applications are listed in confidential work papers to this testimony. The most significant portion of the overall cost increase is due to the number of products under maintenance and the price increases established by the vendors. Most software

maintenance fees are based on the number of people using the product. As we implement more systems that are used by an increasing number of users, costs in these areas increase. The same can be said about our hardware maintenance – new technology implemented throughout the company carries an increased maintenance cost.

Q. By how much have non-labor costs increased as a result of cyber security measures?

A. PGE forecasts an increase of approximately $2.1 million for non-labor O&M costs when comparing 2008 actuals to the 2011 forecast. We describe these costs in more detail in Section IV, Part A, below.

Q. How much of the increasing IT costs are due to AMI?

A. PGE has identified $553,000 in incremental non-labor costs associated with AMI as listed below. (Note: these costs were included in the UE 189 business case related to AMI and are incorporated in PGE's calculations of net AMI savings.) Specifically, the increased AMI costs are due to:

- $78,000 for Oracle database maintenance.
- $147,000 for data storage costs related to the increasing requirements of the meter data consolidator.
- $71,000 for server hardware and software maintenance.
- $108,000 for third-party-owned tower leases.
- $126,000 for backhaul circuit leases, tower inspection fees, and tower climbing training.
- $23,000 for additional maintenance on the World Trade Center (WTC) and Portland Service Center networks and the Regional Network Interface (i.e.,

routers and network gear to support the connections from our data center to the tower gateway base stations).

Q. Are there any additional non-labor costs increases for IT?

A. Yes. PGE forecasts approximately $190,000 for additional leased communications circuit costs associated with 1) the Open Access Technology International application as used by PGE’s Power Operations group, 2) the data connection between the Clackamas Training Center and WTC for business and training purposes, and 3) escalation on general circuit leases.

C. Cost Savings and Efficiencies

Q. Has PGE implemented any programs to reduce IT costs?

A. Yes. PGE has recently implemented several programs to reduce IT costs through contract management, virtual servers, reduced data-retention time periods, new data storage technology, and skipping some non-essential software releases.

Q. What has PGE accomplished through contract management?

A. PGE implemented this program several years ago in order to achieve cost savings through more beneficial terms in IT contracts. Specifically, we negotiated savings in the following areas:

- Discounts for IT contractors based on the number of contractors employed and the duration of their service.
- Caps on many of our IT software licenses and maintenance agreements.
- Discounts based on bundled purchases rather than individual and separate purchases.
- Consistent contract administration.

- Better tracking and reallocation of software licenses.
- Enterprise licensing agreements.

Q. How much has PGE saved through Contract Management?

A. By having a contract management group that actively negotiates and enforces PGE's technology purchases, we estimate that we have saved the following amounts from this program (based on specific discounts to individual contracts):

- 2006 – $519,000
- 2007 – $722,000
- 2008 – $358,000
- 2009 estimated – $641,000

Q. Please describe the virtual server program.

A. The process of server virtualization involves consolidating many stand-alone servers to one or more shared servers by use of specialized operating system software. This is a fairly recent innovation, for which PGE waited until it was a proven technology but then moved quickly to take advantage of the cost savings that it could afford.

Q. How much has PGE saved through server virtualization?

A. This approach has allowed PGE to reduce the need for additional Windows servers from 201 down to eight, saving approximately $1.5 million in hardware capital costs.

Q. What did it cost to implement this program?

A. The cost of the program is approximately $350,000, leading to a net savings of approximately $1.2 million.

Q. Is it possible to virtualize all servers?

A. No. Certain servers cannot be virtualized because the resource requirements are too large and others cannot be virtualized because the proprietary nature of some applications requires dedicated servers. For servers that were virtualized, PGE applied the process under the following conditions: 1) old servers became obsolete and needed to be replaced, or 2) new servers were required. This is an ongoing process and we expect more savings in the future.

IV. Major IT Projects

A. Cyber Security

Q. Please describe PGE's efforts toward cyber security.

A. PGE has implemented a Security Roadmap to reduce our security and data risk while building our security capability and architecture to a level that is consistent with both current industry practices and regulatory requirements. The primary implementation of this project will begin in 2010 and continue through 2015. Total capital cost over the six years of the project is estimated at $12.5 million. Beyond that, PGE will address emerging issues and compliance requirements as they arise.

Q. Why are you implementing this project now?

A. PGE employed Ernst & Young LLP in 2008 to perform a data security assessment, which indicated that our cyber security risk exposure is in need of significant reduction. In addition, based on cyber threats to the national infrastructure, there is a significant federal push to bring the utility industry as a whole into a security model similar to that of banking institutions and other industries considered to be "high risk." Consequently, PGE faces significantly increasing regulatory requirements and guidelines provided by NERC, FERC, Department of Homeland Security, Sarbanes-Oxley, and the OPUC to address the growing number of threats and vulnerabilities such as viruses, worms, hacker sophistication, and potential terrorist activities.

Q. What cyber security measures has PGE implemented in the past?

A. In the past, PGE implemented security solutions for problems already identified on a per-need basis. This has resulted in ad-hoc processes and intermittent capabilities to protect

PGE assets. Although not an absolute "best practice", it was typical of industry standards and served to keep costs lower for customers.

Q. Why is this approach no longer adequate?

A. The current approach is no longer adequate to support the emerging needs due to resource constraints and time spent on implementing and maintaining manual processes and solutions. Additionally, regulatory requirements are increasing the need to automate and proactively manage threats and risks.

Q. What are the consequences of not implementing the proposed cyber security measures?

A. By deferring this project, PGE would be subject to an increasing risk of data breaches, data loss, or compromised operations by hackers who could exploit vulnerabilities in PGE's cyber assets. We would also face financial penalties due to non-compliance with legal and regulatory requirements. In short, PGE cannot afford to defer this work.

Q. By how much do you forecast non-labor O&M to increase in 2011 due to the cyber security project?

A. We project that the program will require approximately $2.1 million in non-labor O&M and consist of the following components:

- $121,000 in contract labor to assist in building a risk management framework, documentation, templates, and training.
- $145,000 for specialized security training for 15 application and coding developers.
- $116,000 in contract labor for sensitive data clean-up and to configure and structure certain data sets to align with a new software tool used to implement

identity and access management to critical cyber assets and systems, including tracking and reporting of cyber access by employees and contractors.

- $90,000 in contract labor for asset and file tagging, which provides classifications as to how they are to be protected.
- $200,000 for software purchases (PGE is currently reviewing this cost to determine if it is more appropriately classified as capital).
- $675,000 in contract labor to upgrade and configure identity and access management tools. These address risks associated with redundant or inappropriate user accounts plus access rights and privileges to certain data and critical applications. Expanding access management capabilities (beyond finance applications and Sarbanes-Oxley compliance-enabling software) is necessary based on the number of PGE employees and contractors plus FERC requirements that transmission, generation and trading activities remain partitioned. This will also provide centralized access control (i.e., for addition, modification, or termination of access) for all PGE cyber assets, which will increase the efficiency in audits pertaining to user access and associated reporting.
- $200,000 in contract labor for security architecture review. This work is necessary because PGE will be implementing substantial technology updates over the next several years (see Section IV, Part B, below) and we need to ensure they are properly designed prior to implementation to avoid conflicting technologies.
- $160,000 for audit services to test and ensure systems are secure and "hardened," which means that the systems are functioning as intended but are secure in the most optimal way given current standards.

- $375,000 for maintenance costs on software and hardware specifically applied to security requirements.

B. 2020 Vision Strategy

Q. Please describe the 2020 Vision strategy.

A. During the next 10 years, PGE is planning to implement a set of projects that collectively modernize and consolidate our technology infrastructure. The ultimate purpose of this program, which we call "2020" Vision, is to replace a multitude of existing software applications with fewer "enterprise" applications that provide integrated functionality for PGE's operations.

Q. How many applications do you plan to consolidate through the 2020 Vision project?

A. PGE's current projections are that we can achieve the following consolidations:

- Financial Management – reduce 11 current applications to 5 or fewer applications.
- Asset and Work Management – reduce 68 current applications to 5 or fewer applications.
- Timekeeping – reduce 8 current applications to 1 application.
- Mapping and Design – reduce 29 current applications to 5 or fewer applications.

Q. Why does PGE have so many applications in these areas?

A. This situation is typical not only for electric utilities but for most companies; PGE is not unique. Historically, the market simply did not provide single solutions that could meet a company's entire set of IT requirements. Instead, specialized applications were brought to market to meet specific needs. Operating areas within a company then chose those applications that most benefited them. Consequently, the common IT strategy since the 1980s has been to purchase or develop the necessary software as individual requirements arise (i.e., on a task- or department-specific basis), which leads to a patchwork of customized and separate applications.

Q. What has changed in the IT environment to address this fragmentation and allow the degree of consolidation that you plan to achieve?

A. As we mentioned earlier, the critical factor is that enterprise or system-wide applications have matured in the last few years to where it is now practical to implement them. Integrated solutions are now available from leading software vendors, which are focused specifically on the utility industry and support end-to-end, industry-standard processes. Instead of using processes designed around outdated software, PGE will be able to take advantage of built-in integrations provided by modern software applications that support standard, best-practice business processes.

Q. What, specifically, are you proposing to implement and over what period?

A. The 2020 Vision program is intended to be ongoing through the year 2020. Currently, we have mapped out the first three phases that span the first seven years and consist of the following:

- Phase 1 – begun in 2009, will be completed in 2011, and comprised of:
  - Financial Systems
  - Supply Chain
  - Enterprise Asset Management (EAM) for thermal plants and selected distribution assets
  - Upgrade to Distribution Work Management system
  - Upgrade to Human Resource systems
  - Hardware and infrastructure in support of these projects
- Phase 2 – begin in 2011, will be completed in 2014, and comprised of:

  - Geographic Information System (GIS) and graphic work design tools
  - Mobile Workforce Management (MWM)
  - Outage Management System (OMS)
  - Implementation of an additional module to our Human Resource system
  - Hardware and infrastructure in support of these projects
- Phase 3 – begin in 2013, will be completed in 2016, and comprised of:
  - Document Management System upgrade
  - Distribution Asset Management
  - Distribution Work Management
  - IT Work and Asset Management
  - Hardware and infrastructure in support of these projects

Q. Why is PGE proposing to implement this program now?

A. There are numerous reasons to implement 2020 Vision now:

- Current technology obsolescence – Many of the systems that PGE plans to replace have been in service for many years and are either no longer supported by the vendor or will not be supported in the near future. When systems are no longer supported, upgrades and enhancements are no longer provided by the vendor to meet new requirements, patch security threats, or fix bugs. At that point, PGE would have to perform this work in-house at significant cost and risk.

  For example, PGE's financial system is 26 years old, the vendor is no longer making enhancements, and we need a system that can accommodate the International Financial Reporting Standards (IFRS) that are currently expected to be required by 2012 (i.e., 2014 but with two prior years of detail). PGE can incur additional costs to upgrade these legacy systems with the new requirements but this means we would not have ongoing vendor support as the technology and user requirements continue to change.

- Operational efficiencies through process improvement – inefficient and redundant processes will be identified and improved, thereby increasing operational efficiency. Examples of benefits include:
  - Elimination of manual processes, reduction of redundant work, improved workflow, and more efficient reconciliation. In addition, PGE expects to: 1) have a more effective capital and O&M budgeting process, 2) have enhanced ability to forecast multiple scenarios and analyze data, 3) capture PGE's financial commitments and expected cash flows automatically, and 4) strengthen our internal controls by automating current manual controls.
  - Optimization of resources across maintenance, construction, and inspection groups. Currently, resource assignments are assembled manually and dispatched by individual workgroups, limiting the ability for workforce leveling or resource optimization across the organization. A fully integrated work and asset management system, built on standard business processes, will reduce the amount of manual reconciliation and handling required for scheduling and dispatch. In addition, it will enable PGE to compare and contrast similar work activities by crew or region.
- Improvements in customer service – Customer information can be connected to: 1) the assets associated with providing electric service (i.e., transformers, poles, wires, meters, etc), and 2) the PGE resources responsible for building, maintaining, and repairing those assets. For example, an Asset Management system that is fully integrated with GIS and Outage Management applications, in

conjunction with our Smart Meters, can create a foundation for future projects to allow customers to access their service information and the status of restoration efforts in real-time.

Currently, there is no intelligent connectivity model for PGE's distribution system and outages are determined via "roll ups" of circuit maps. This results in additional time spent diagnosing the outage, incomplete knowledge of the outage boundaries and affected customers, and less than optimal crew dispatching for restoration efforts.

- Improved asset utilization – Currently, PGE does not have the means for a consistent asset management strategy or process, across organizations and individual work groups, to determine how best to utilize our assets. Because departments independently conduct narrowly scoped work on the same assets, without a holistic view of the work required, some re-work and revisits to any given asset may occur. With up-to-date technologies and standardized processes PGE can benefit from "just in time" inventory and we will have more accurate information to identify when critical assets need replacing rather than use a time-based replacement strategy.
- Smart grid connectivity – With PGE's current fragmented systems, smart grid data will not be available across applications and cannot be fully utilized. Consequently, PGE's current technology will become a bottleneck to realizing future smart grid potential. By implementing the 2020 Vision program, with process improvement and standardization, PGE can use real-time, smart grid information to optimize PGE's power delivery system (e.g., transformers and other assets) and realize more dependable and more rapid outage identification.

- Knowledge transfer – Much of PGE's knowledge of operational practices resides within the individuals currently performing the work. Over the next five to ten years, we anticipate that a significant percentage of our IT workforce will retire. The effort required to migrate work processes from legacy applications to new systems offers a unique opportunity to address how we capture process knowledge and train new employees, so that as much as possible, our historical contexts, policies, and ways of working will not be lost in the labor transition.
- Time to complete – Because the systems will take up to seven years to fully implement and given the needs/benefits identified above, PGE believes it is inappropriate to delay the program beyond the current schedule.

Q. What would it cost to delay the project?

A. Based on the last four years of historical costs, PGE estimates that without implementing the proposed projects, the cost of maintaining and upgrading PGE's existing systems over the next five years will be approximately $44 million. This would maintain current functionality and business processes and provide little or no additional business value, while at the same time would:

- Leave PGE unable to respond to increasing demands for real-time information, changing customer needs, and increasing regulatory requirements;
- Impair PGE's ability to pursue business process improvement efficiencies;
- Require continued significant investment in IT integrations of disparate systems in an attempt to provide the seamless flow of data across applications, such as the data required for and provided by the Smart Grid;
- Put PGE at risk of losing valuable knowledge currently embodied in long-time employees' understanding of how to work across disparate information systems;

- Weaken PGE's ability to attract and retain new talent to replace retiring workers;
- Inhibit PGE's ability to leverage the capabilities of Smart Grid technologies currently being implemented; and
- Be analogous to paving cow-paths rather than investing in a modern freeway system.

At the end of the five years, however, PGE would still need all the functionality that the 2020 Vision project will provide, which means we would still have to replace the old systems.

Q. How much does PGE expect the full 2020 Vision implementation to cost?

A. As noted above, 2020 Vision consists of three initial phases, which include both capital and O&M costs (development and ongoing). A summary of the software included in these phases is provided as PGE Exhibits 602 and 603 and summarized in Table 2 below. Costs for phase 1 are fairly current, whereas costs for phases 2 and 3 are based upon assumptions reflecting today's environment, (i.e., known technologies, sequencing requirements, current regulatory environment, cost of outside services, etc.), which are subject to potentially changing conditions throughout the next 10 years.

Table 2
Summary 2020 Vision Costs ($ Millions)

Phase	Capital	Development O&M
Phase 1 (2009-2011)	42.5	4.5
Phase 2 (2011-2015)	56.8	9.3
Phase 3 (2013-2016)	22.4	5.2
Totals	**121.6**	**19.0**

Q. What is PGE doing to manage this project effectively?

A. Typically in IT projects everywhere (not just PGE or utilities), cost overruns can be attributed to lack of clarity about requirements and scope, poor estimates, or technical risks. To ensure success of this initiative, we are: 1) putting strong governance policies in place for early identification and mitigation of risks, 2) managing a common high-level schedule to ensure coordination between individual projects, and 3) tightly managing scope for the defined projects. As we complete the design stage of each project, we will refine cost and labor estimates to account for clarified requirements to ensure scope, schedule, and costs are still aligned with expectations.

Q. How do you know the cost estimate is valid?

A. As noted above, enterprise solutions are now available from leading software vendors. The programs already exist and do not require development or major customization. Instead, the primary IT effort will be to configure the programs to PGE's specifications and to perform integrations as necessary. The corresponding business effort required is to fully define business processes and metrics that will be mapped to the new systems, and to participate throughout the implementation life-cycle to ensure delivery of the agreed scope. We worked with implementation consultants who specialize in this type of integration work to estimate probable professional services costs, which we plan to leverage to complete the project.

Q. What method did you use to determine which integration consultants and software systems to employ?

A. At the start of the process, PGE issued a request for cost opinion, which asked implementation consultants to submit initial estimates for the overall project path, including integration services, as described above. Based on those estimates, we issued a request for proposal (RFP) and selected an integrator for PGE's new financial system (phase 1 project). In addition, we are currently in the RFP process for selecting an integrator for the enterprise asset management assessment (also phase 1 project). In this way, we have a roadmap for the overall program, but we select software and integration consultants for individual components as we proceed through the designated phases.

Q. Which components and capital costs are specifically included in the 2011 test year forecast?

A. The 2011 forecast includes the components and capital costs as summarized in Table 3 below.

Table 3
2020 Vision Capital Costs in the 2011 Forecast
($ Millions)

Phase 1	2009	2010	2011	Total
EAM Foundation	3.21	4.53	6.29	14.03
Financial System	1.90	16.61	5.60	24.11
Infrastructure and Program office	0.10	3.10	1.13	4.33
Totals	**5.21**	**24.24**	**13.02**	**42.47**

Q. How are the capital costs included in rate base?

A. Because all the phase 1 projects are expected to close before December 31, 2011 (each component has individual jobs that are projected to close at specific times from late 2010 into 2011), their revenue requirement is based on average rate base similar to any other new plant-in-service.

Q. What capital costs do you forecast for the subsequent phases?

A. We forecast the following capital costs (see PGE Exhibit 602 for a summary by project):

- Phase 2 – $56.8 million to be incurred between 2011 and 2015
- Phase 3 – $22.4 million to be incurred between 2013 and 2016

Q. Over what period are you proposing to depreciate and/or amortize these assets?

A. Because total 2020 Vision capital costs are projected to equal approximately $121.6 million and because we expect these programs to be in service for many years, PGE is proposing 10-year lives for the associated software costs. This treatment is similar to our customer information system, which was included in our UE 115 rate case and approved by Commission Order No. 01-777.

Q. What development O&M costs are associated with the 2020 Vision program?

A. For 2011, PGE forecasts that we will incur approximately $3.7 million in development O&M costs, consisting of $2.9 million for phase 1 and $700,000 for phase 2. During the relevant implementation period (2011 through 2016), we forecast a total of approximately $17.5 million in development O&M costs for all three phases.

Q. Why is this O&M required?

A. Large IT projects typically involve several stages of activity that are classified as either capital or development O&M. The initial stage of analyzing and planning the project is recorded as O&M costs. Because PGE has not previously undertaken an IT project of this magnitude, we plan to rely more on third-party consultants – with expertise in the governance of large-scale software implementation – to provide guidance in scoping, scheduling, cost estimates, process evaluations, and planning documentation in advance of software installation and configuration. These costs must be considered O&M. After those activities are complete, then designing, developing, and testing of the software and all of its components are recorded as capital costs. Subsequent to these activities, PGE will incur additional O&M for certain implementation costs (such as development of business process training and post-implementation user support), data migration, and closing activities (e.g., retirement of the old system). In addition, certain project office costs for the program cannot be capitalized based on GAAP.

For each phase of the 2020 Vision program, these activities are necessary for successful completion. Consequently, based on the overall size of the project, the number of systems being replaced, and the time period necessary to fully deploy these systems, development O&M costs can be significant.[3]

Q. Is PGE incurring any development O&M costs prior to the test year?

A. Yes. As listed in PGE Exhibit 603, PGE expects to incur approximately $1.6 million in development O&M costs for 2020 vision in 2009 and 2010.

Q. How much of the development O&M costs have you incorporated into the test year forecast?

A. PGE proposes to incorporate one-fifteenth of the 2011-2016 development O&M costs in the test year forecast and then defer any actual costs incurred over this amount into a regulatory asset between 2011 and 2016. Beginning in 2016, we propose to amortize the regulatory asset over 10 years. In this way, the regulatory asset will:

- Accumulate costs during the project development period, which will coincide with the accumulation of 2020 Vision capital costs; and
- Amortize costs over 10 years beginning in 2017, which will coincide with amortization of 2020 Vision software that will have closed to plant by the end of the project.

Q. Why are you proposing this mechanism?

A. We do so for two reasons. First, these represent prudent and necessary costs that, given their overall magnitude, should be spread over the life of the project, including both the development period and amortization period. Second, this will significantly reduce the rate

[3] Specific details on components of development and ongoing O&M for 2020 Vision are included in work papers to this testimony.

impact of these costs as compared to including them in test year forecasts as they are expected to be incurred.

Q. In addition to 2020 development costs and their associated mechanism, do you also expect ongoing O&M in 2011 associated with this project?

A. Yes. We forecast that PGE will incur approximately $1.4 million in ongoing O&M in 2011 for 2020 Vision. We propose, however, to include the average of the 2011 and 2012 levels of ongoing O&M in the 2011 revenue requirement (i.e., approximately $1.6 million).

Q. What is the reason for this proposal?

A. Because 2020 Vision is a large, multi-faceted program, its scope increases each year for several years and the ongoing O&M will correspondingly increase during that period. Given that these are also prudently incurred O&M costs, this treatment will simply afford PGE the opportunity to recover the increasing O&M for 2011 and 2012. Additional increases can be addressed in subsequent rate cases.

Q. What is the ongoing O&M cost expected to cover?

A. The ongoing O&M for 2011 represents maintenance agreements for phase 1 software and hardware. The primary components of this are $470,000 for the financial system software maintenance, $560,000 for the Enterprise Asset Management system software maintenance, and $343,000 for hardware/infrastructure maintenance. The software maintenance gives PGE the rights to future upgraded versions of the software and, in general, costs about 20% of the initial license purchase cost of the software. Maintenance for hardware/infrastructure also covers requirements for disk space, data backup, supporting applications, and database support. These costs increase to $1.7 million in 2012 as we begin to add maintenance agreements for phase 2 software and hardware.

Q. What are your ultimate recommendations regarding IT costs in the 2011 test year forecast?

A. We propose that the Commission issue an order approving PGE's 2011 test year revenue requirement, which includes the following related to IT:

- $42.5 million in capital costs associated with phase 1 in average rate base.
- $1.2 million in development O&M costs with the difference between $1.2 million and actual incurred costs to be deferred into a regulatory asset. More specifically, each year from 2011 until 2016, PGE will include $1.2 million for development O&M in base rates and defer the difference between the $1.2 million and actual annual incurred costs. We forecast that the regulatory asset will be $2.5 million for 2011 and accumulate to approximately $11.6 million, which will then be amortized over the next ten years, beginning in 2017. The regulatory asset is included in PGE's test year rate base.
- $1.6 million for ongoing O&M to reflect the increase in scope from 2011 to 2012.

V. Qualifications

Q. Mr. Henderson, please provide your qualifications.

A. As vice president of PGE for Information Technology, I am responsible for the infrastructure, operations and system development of all information systems. This includes developing a strategic plan for information technology and implementing enhanced project management and methodology. I joined PGE in 2005 after serving as Chief Information Officer at Stockamp & Associates since 2003. Previously, I spent eight years as senior IT manager for Willamette Industries, Inc. and was named vice president and chief information officer in 1998. I received a bachelor's degree in management from Harding University in Searcy, Ark., and an MBA from the University of Texas. I am also a Certified Public Accountant in Oregon.

Q. Mr. Hosseini, please state your educational background and experience.

A. I earned a Bachelor degree in Finance and MBA from Portland State University, where I teach courses in Management, Finance, and Information Technology. I have also taught Management and Human Resources courses for the University of Phoenix and the Utility Management Certificate course for Willamette University. I currently work as the Director of Information Technology Strategy at PGE. Prior to this, I held leadership positions in the Human Resources, Organizational Development, Finance and Accounting, Business Decision Support, and Distribution departments at PGE. Additional experience includes retail sales management, restaurant management, as well as consulting work for a variety of clients.

Q. Does this complete your testimony?

A. Yes

List of Exhibits

PGE Exhibit	**Description**
601	Summary of IT Costs by Operating Area
602	2020 Vision – Capital Costs by Year
603	2020 Vision – Development O&M Costs by Year

Funtion	2006 ACTUALS	2007 ACTUALS	2008 ACTUALS	2009 FCST (9+3)	2010 FOM	2011 FOM	2008 Actuals vs 2011 Forecast	Annual % delta 2008-2011
Production								
Assigned	730,374	728,893	859,878	892,920	944,441	969,184	109,306	4.1%
Allocated	2,403,515	2,828,035	3,054,422	3,727,264	4,127,990	5,590,510	2,536,088	22.3%
Total Production	3,133,888	3,556,928	3,914,300	4,620,185	5,072,431	6,559,694	2,645,394	18.8%
Power Operations								
Assigned	995,305	880,438	773,530	799,467	1,272,412	1,444,873	671,343	23.2%
Allocated	878,020	1,223,642	1,282,809	734,832	827,484	1,119,888	(162,921)	-4.4%
Total Power Ops	1,873,325	2,104,080	2,056,338	1,534,298	2,099,896	2,564,761	508,423	7.6%
Transmission								
Assigned	815,530	972,056	1,161,920	1,190,683	1,225,959	1,282,337	120,417	3.3%
Allocated	880,115	318,348	491,183	424,128	477,617	646,452	155,269	9.6%
Total Transmission	1,695,645	1,290,404	1,653,103	1,614,810	1,703,576	1,928,789	275,686	5.3%
Distribution								
Assigned	1,535,473	1,591,195	1,700,850	1,434,604	1,933,782	2,070,219	369,369	6.8%
Allocated	7,563,194	8,536,358	8,714,520	9,111,300	10,263,573	13,891,944	5,177,424	16.8%
Total Distribution	9,098,668	10,127,552	10,415,370	10,545,904	12,197,355	15,962,163	5,546,793	15.3%
Customer Accounting								
Assigned	8,041,535	7,212,284	6,337,568	6,478,971	6,557,527	8,048,178	1,710,610	8.3%
Allocated	6,572,927	7,702,719	7,603,052	7,171,636	8,075,731	10,926,516	3,323,465	12.8%
Total Customer Acctng	14,614,462	14,915,003	13,940,620	13,650,607	14,633,258	18,974,694	5,034,074	10.8%
Customer Service								
Assigned	11,533	43,049	49,171	20,213	15,015	15,660	(33,511)	-31.7%
Allocated	343,437	324,199	445,425	416,310	468,784	634,272	188,847	12.5%
Total Customer Svcs	354,971	367,248	494,596	436,523	483,799	649,932	155,336	9.5%
A&G								
Assigned	2,469,169	2,859,931	2,930,255	3,198,081	2,824,767	3,846,177	915,922	9.5%
Allocated	4,559,705	4,323,274	4,807,401	5,182,956	5,834,270	7,891,871	3,084,470	18.0%
Total A&G	7,028,874	7,183,204	7,737,656	8,381,037	8,659,037	11,738,048	4,000,392	14.9%
Totals								
Assigned	14,598,919	14,287,846	13,813,173	14,014,938	14,773,903	17,676,628	3,863,456	8.6%
Allocated	23,200,914	25,256,574	26,398,811	26,768,427	30,075,449	40,701,453	14,302,642	15.5%
Grand Total	37,799,833	39,544,419	40,211,984	40,783,365	44,849,352	58,378,081	18,166,098	13.2%
Less Labor Adjustment						(1,500,000)	(1,500,000)	
Subtotal	37,799,833	39,544,419	40,211,984	40,783,365	44,849,352	56,878,081	16,666,098	12.3%
Less 2020 Vision Deferral						(2,490,688)	(2,490,688)	
Plus 2020 Vision On-going for 2012						240,685	240,685	
Net IT O&M	37,799,833	39,544,419	40,211,984	40,783,365	44,849,352	54,628,078	14,416,095	10.8%

2020 Vision Development O&M Costs

Phase	Project	Job No.	Job Description	2009	2010	2011	2012	2013	2014	2015	2016	Total
Phase 1	Enterprise Asset Management Foundation	26538	EAM Foundation Assessment	102,000	202,446							304,446
		26539	Maximo Thermal Plant Upgrade and Consolidation			88,454						88,454
		26540	WMS Upgrade		16,130							16,130
		26541	Maximo Software Purchase									
		26542	EAM Foundation		104,866	1,728,535						1,833,400
	Financial System Replacement	26535	PeopleSoft Financials and PeopleSoft Supply Chain	300,251	417,093	206,135						923,478
		26536	PowerPlant Modules	100,000								100,000
		26537	Finance project software									
	Infrastructure and Program Office	26543	Program Office	88,080	253,935	739,648						1,081,663
		26544	Infrastructure Phase 1			161,898						161,898
		26566	Infrastructure Software									
Phase 1 Total				590,331	994,469	2,924,669						4,509,469
Phase 2	GIS				-	567,737	1,027,709	1,134,139				2,729,585
	MWM						446,929	662,742	433,303			1,542,975
	OMS							1,079,241	510,430			1,589,671
	Infrastructure (Phase 2)						233,913	5,366	2,243	2,344		243,867
	Mobility Foundation					161,781	315,227	497,242	329,894	337,482		1,641,626
	PeopleSoft Time and Labor						189,282					189,282
	Program Office						680,171	647,257	16,500			1,343,928
Phase 2 Total					-	729,518	2,893,231	4,025,988	1,292,370	339,826		9,280,933
Phase 3	Program Office								658,305	687,832	458,615	1,804,752
	DMS Upgrade							119,252	62,309			181,561
	EAM Distribution (WM)								443,787	1,639,793	750,950	2,834,530
	EAM IT								99,045	101,323		200,367
	EAM Supply Chain								223,324	2,344		225,668
Phase 3 Total								119,252	1,486,770	2,431,292	1,209,565	5,246,878
Grand Total				590,331	994,469	3,654,187	2,893,231	4,145,240	2,779,140	2,771,118	1,209,565	19,037,280

Table of Contents

I. Introduction

Q. Please state your names and positions with 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 and for decommissioning the Trojan nuclear plant.

My name is Arya Behbehani. I am the Manager of Environmental Services at PGE. I am responsible for compliance with environmental regulations as it pertains to generation and distribution of electricity.

Our qualifications are provided in Section VI.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to support Operations and Maintenance Costs (O&M) and rate base related costs associated with PGE's long-term power supply resources, both owned plants and contracts. We also update relicensing information regarding our hydro facilities.

Q. What is the primary goal of PGE's plant related activities?

A. The primary goal of our plant related activities is to maintain high levels of plant availability and system reliability as the composition of our production resource mix evolves over time. High availability allows our power operations group to dispatch plants whenever their variable costs are less than the market price of power, thereby keeping net variable power costs low. High system reliability ensures that we meet our obligation to serve on-demand customer loads.

Q. Does your testimony explain how you are achieving this primary goal?

A. Yes. In Section III-A, we discuss activities that maintain the reliability of our power plants. For example, when longer planned maintenance outages are necessary, we schedule them at times of the year when power prices are forecast to be low. Continued good plant availability directly influences the test year net variable power cost forecast presented in PGE Exhibit 400, and thus directly benefits our customers.

Q. How do you organize your testimony?

A. We organize our testimony into the following sections:

- Section I: Introduction
- Section II: Resource Summary (Plants, Power Contracts, and Transmission)
- Section III: Plant and Power Operations (O&M, FTEs, Capital Additions, and Environmental Services)
- Section IV: Cost Efficiencies
- Section V: Hydro Relicensing Update
- Section VI: Qualifications

II. Resource Summary

A. Power Supply Resources

Q. Have you prepared an exhibit that shows all of PGE's power supply resources for the 2011 test year?

A. Yes. PGE Exhibit 701 lists PGE's supply resources, their capacity, and their expected energy output.

Q. Have PGE's long-term power supply resources changed significantly since the UE 197 and UE 209 (RAC) proceedings?

A. The only significant change is the addition of the third phase of our wind resource, Biglow Canyon; we discuss Biglow Canyon phase 3 O&M in Section III-A, 3. PGE Exhibit 300 discusses the overall plant. In addition to Biglow, we have expanded our dispatchable standby generation (DSG) capacity.

Q. How large is PGE's DSG capacity?

A. As of January 2010, we have 23 dispatchable standby generation sites (containing 37 generators) completed that can provide 48.0 MW of reliable diesel-fired capacity at peak times. By December 2010, we will have added at least 8 new sites, for a total of 31 sites (56 generators) and 75.2 MW. This is a substantial increase from the end of 2007, when we had completed only 19 sites with a combined capacity of 39.0 MW.

Q. Does PGE plan to add DSG capacity in the future?

A. Yes. PGE is targeting an additional 15 MW of dispatchable standby capacity annually for the next 5 years. DSG projects have reduced operating costs compared to larger capacity projects of 20 MW or more. The focus on expanding DSG capacity allows PGE to obtain necessary capacity at reduced costs in today's difficult economy.

Q. Besides peak-load capacity, are there other benefits that the dispatchable standby generators provide?

A. Yes. Because PGE can start these resources within ten seconds, they provide a block of reserve power for our system. In 2011, PGE may be required to maintain reserves equal to 3% of generation and 3% of total load; of the total 6%, half must be spinning. Dispatchable standby generators do not qualify as spinning reserves, but they can help provide the remaining operating reserves – 1.5% for generation and 1.5% for total load. Thus, the existing 48.0 MW of dispatchable standby generation can provide non-spinning reserves for almost 3,200 MW of generation or total load.

In addition to providing non-spinning reserves, dispatchable standby generation, when operating, acts like a demand response program – it supplies most or all of dispatchable standby generation customers' loads, effectively removing these loads from the grid. Finally, dispatchable standby generation adds some fuel diversity to PGE's resource mix.

Q. Is PGE's need for capacity resources growing?

A. Yes. As discussed in our Integrated Resource Plan (IRP) (Docket No. LC 48), PGE traditionally has had greater energy than capacity needs. With reduced access to hydro, increased reliance on wind generation, and growth in summer peaking loads, PGE's capacity needs now exceed our energy needs.

Q. Why does PGE need flexible capacity resources?

A. Capacity resources have a dual purpose. First, they enable a utility to meet its obligation to provide safe and reliable power to customers during peak demand periods. Specifically, these resources help meet customer loads, sometimes under conditions which may be extreme, but of short duration during the year. For example, we might have an immediate need for power if one of our major thermal resources suddenly "trips" (shuts down or "goes off-line") or if loads increase rapidly due to an extreme temperature event. Second, capacity resources allow for the integration of intermittent renewable resources. Our increased level of intermittent resources, required to meet the Oregon Renewable Portfolio Standard, necessitates that we maintain flexibility and load following capability in our generation portfolio.

Q. What criteria does PGE use in its selection of capacity resources?

A. We consider two primary criteria. The first and most important is that the resource must be reliably dispatchable on demand. The second most important criterion is low fixed costs for customers. Possible margins on wholesale energy are not a driving consideration because capacity resources generally have high variable costs, making them uneconomical to run except in extreme events.

Q. Do capacity resources selected by PGE have to compete with other capacity alternatives?

A. Yes. These capacity resources must compete against other capacity-like resources. Large capacity projects (those which have durations greater than 5 years and are larger than 100 MW) must participate and be selected through a specific Request for Proposal process using an independent observer, as called for by OPUC guidelines.

Q. Does PGE have plans for major new power supply resources in the future?

A. Yes. PGE's latest IRP was filed on November 5, 2009. The plan includes additional base-load plant resources such as a combined cycle combustion turbine and up to 200 MW of flexible peaking capacity generation. However, none of the costs of these potential future projects are included in the 2011 test year.

B. Transmission Resources

Q. Why does PGE require long-term transmission contracts?

A. PGE is a transmission dependent utility. That is, we do not have enough PGE-owned transmission to move our generated/purchased energy to our system. Therefore, we must purchase adequate transmission capacity from third-party providers or build transmission to reliably and cost-effectively meet our customer load obligations. Our transmission dependence stems from our need to transmit energy from remote generating resources, long-term contractual delivery points, and short-term markets to meet our customers' needs. Even with efficient new resources such as Port Westward, PGE can sometimes lower costs for customers by purchasing energy on the wholesale market and then arranging to deliver that energy to our service territory.

Q. What major transmission agreements does PGE have with Bonneville Power Administration (BPA)?

A. PGE has three major transmission agreements with BPA. These are:

- Point-to-Point (PTP) agreements,
- AC/DC Intertie agreement (also involves PGE Transmission Services), and
- Montana Intertie agreement.

Q. Please describe the PTP agreements.

A. The PTP agreements provide PGE with firm transmission rights across BPA's transmission system from one point of receipt (POR) to one point of delivery (POD). This transmission can also be redirected firm (when transfer capacity is available) and non-firm from alternative PORs to alternative PODs. These agreements include eleven PTP service agreements resulting from the conversion of PGE's legacy Integration of Resources (IR) agreement, which expired on December 31, 2009. PGE Exhibit 702 summarizes all of PGE's PTP agreements.

Q. Please describe the IR agreement conversion.

A. PGE's IR agreement with BPA allowed PGE to deliver 2,218 MWs of power from our thermal resources, the Mid-Columbia hydros, and a system (capacity) purchase from Spokane Energy to the PGE system and to the head of the Intertie. A renewal of the IR agreement was not possible. Therefore, PGE negotiated to replace the IR contract with eleven PTP agreements, which continue to provide PGE access to transmission for the same purposes in a more flexible manner at no additional cost.

Q. Please describe the AC/DC Intertie Agreement.

A. PGE's AC/DC Intertie rights are defined in the BPA/PGE Intertie Agreement, which is in effect as long as the facilities of the Joint AC Intertie are operable. Under this agreement, PGE Transmission Services (PGE Transmission) controls 850 MW[1] of southbound rights on the AC line from John Day to the California-Oregon border. PGE's power operations[2] group has purchased 200 MW of rights on the southbound AC line that it uses to sell excess power to California. This 200 MW purchase was made pursuant to PGE Transmission's open access tariff. The power operations group also has rights to 100 MW of DC Intertie pursuant to an exchange of AC for DC (resulting in a decrease in AC rights from 950 MW to 850 MW) under the BPA/PGE Intertie Agreement.

Q. Please describe the Montana Intertie agreement.

A. This agreement represents an exchange of firm transmission rights between PGE and BPA that enables PGE to transmit energy from our share of Colstrip Units 3 and 4 to BPA's

---

[1] PGE controls 850 MW of the AC Intertie under the Intertie Agreement. The 850 MW includes 75 MW owned by Bank of America Leasing. An additional 13 MW of transmission capacity is provided (for a fee) to Bank of America Leasing to permit them to transmit 88 MW of power to San Diego Gas & Electric.

[2] PGE's power operations group is also called "PGE Merchant" to distinguish it from PGE Transmission under FERC's open access policies.

system at Garrison, located in Western Montana. PGE then uses BPA PTP (Garrison to PGE's system) to move the power to our service territory. The Montana Intertie agreement provides PGE with 280 MW of firm transmission on BPA's line from Townsend to Garrison in exchange for BPA rights of firm transmission on the Colstrip line from Townsend to Broadview, which is located approximately midway between Townsend and Garrison.

Q. Do you discuss the O&M expenses and capital additions associated with PGE's owned transmission resources?

A. No. Mr. Hawke discusses these transmission requirements in his testimony, PGE Exhibit 800.

III. Plant and Power Operations O&M and Capital Additions

A. Plant O&M

Q. Please summarize PGE's plant and power operations related O&M costs from 2008 to the 2011 test year.

A. Table 1 below provides plant O&M costs from 2008 to 2011.

Table 1
Summary Plant-Related O&M Statistics ($millions)

	2008 Actuals	2011 Test Year
Coal O&M (1)	31.8	41.1
Gas O&M (2)	23.9	28.7
Wind O&M	4.0	11.8
Hydro O&M	11.0	19.4
General Plant O&M	4.7	3.5
Power Operations O&M	13.3	14.1
Totals*	**88.7**	**118.6**

** Does not include Solar or Nuclear*
(1) Adjusted for a reduction to the Boardman budget
(2) Adjusted for the Coyote Springs LTSA and FTEs

Q. What are the primary drivers for the changes in O&M in Table 1?

A. There are several primary drivers, including:

- $3.2 million increase for the planned maintenance outage scheduled at Colstrip in 2011, to overhaul Unit 3 and perform additional maintenance on Unit 4.
- $2.6 million increase for costs related to the disposal of fly ash at Boardman.
- $2.5 million increase related to changes in the IT allocation, including a new allocation for Port Westward. The increase in IT allocations is discussed in more detail in PGE Exhibit 600.
- $1.5 million increase for materials that are related to the Coyote Springs major maintenance planned outage in 2011, but are outside the scope of the Long Term Service Agreement (LTSA).

- $6.3 million increase in the Biglow Service Agreements related to the additions of Biglow Canyon 2 and 3.
- $1.7 million increase related to increases in existing State, USGS, and FERC land fees at various hydro sites.
- $2.0 million increase for the required lead abatement clean-up at Oak Grove in 2011.
- $3.0 million increase related to an increase in labor costs at the hydro sites, primarily for environmental services, licensing requirements, and new park maintenance responsibilities.
- $0.3 million increase in Dispatchable Standby Generation to cover maintenance related to increasing MW capacity.

We provide detailed explanations of plant and power operations O&M cost changes below.

1. Coal Plant O&M

Q. Please discuss the changes in coal plant O&M expenditures shown in Table 1 above.

A. The 2011 coal plant budget is approximately $9.3 million higher than 2008, primarily due to:

- Colstrip costs increase approximately $4.6 million from 2008 to 2011. The primary driver is a major maintenance overhaul planned for Unit 3 in 2011, which results in an increase of $3.2 million for outside services and material. This 51-day outage includes the 44-day outage work and an additional 7-day chemical clean of the boiler. There was no major maintenance work in 2008. The remaining $1.0 million is escalation, increased taxes and labor, cleaning of the boiler and HP turbine, offset by classification of costs for lime chemicals to Net Variable Power Costs (Exhibit 400).

- Boardman costs increase by $4.7 million from 2008 to 2011. There are new disposal costs estimated at $2.6 million for fly ash, an increase in the IT service provider allocation of $0.7 million, an increase in labor (including work related to the 2011 outage) of $0.4 million, and approximately $1.0 million related to materials for the storeroom and maintenance work, as well as miscellaneous items such as oil and lubricants for pumps and valves.

Q. Please explain the disposal costs for fly ash at Boardman.

A. Fly ash is a byproduct of coal combustion. PGE currently sells the ash to vendors, where it is used as an additive to cement and other beneficial uses. However, pending U.S. Environmental Protection Agency (EPA) regulations may classify fly ash as hazardous material. If Boardman's fly ash is classified as hazardous, PGE will be forced to dispose of the material by shipping it to a hazardous waste disposal site; the nearest is located in Arlington, Oregon. The estimated total cost for disposal of hazardous material is approximately $15.0 million. For 2011, we have budgeted $4.0 million for these costs, $2.6 million of which is PGE's share. This $4.0 million estimate is from 2009, before current information was available. This estimate will be re-evaluated should the EPA classify any form of fly ash to be hazardous. (Note: a decision is expected in the first half of 2010).

Q. Is fly ash also an issue at Colstrip?

A. Yes. Boardman produces a "dry" fly ash, while the ash at Colstrip is classified as "wet" fly ash. The EPA is evaluating both dry and wet fly ash as a possible hazardous material.

Q. If the wet ash at Colstrip is considered hazardous, are there potential costs?

A. Yes. The potential costs have not yet been incorporated into the Colstrip budget and, thus, are not yet included in the test year. Should the EPA rule that wet fly ash is a hazardous material, Colstrip could choose to dispose of the wet ash, or they could modify their systems to produce dry ash instead of wet ash.

Q. Please explain the challenges of employee turnover at Boardman.

A. Boardman has experienced higher turnover in the past several years, which creates significant challenges to keep the plant staffed with experienced and fully trained employees. The turnover is a result of three things: 1) employee concern about the future of the Boardman plant, 2) a different union agreement at Coyote, which is favored by many employees and has resulted in transfers from Boardman to Coyote, and 3) many employees at Boardman are at or near retirement.

These vacancies result in higher overtime for employees and additional training to get new employees fully qualified. It takes 2,000 training hours, or approximately 18 months, for the average employee to become fully trained. These factors result in increased labor costs.

Q. Please explain the maintenance cycles at Boardman.

A. Boardman has a planned outage every spring. An overhaul of each of the three turbine units and generator is required every 10 years, resulting in a major extended outage approximately every 5 years. The outages for these major plant components are typically 6 weeks long. The outage duration in other years is typically 4 weeks, and consists of routine repairs to plant components (e.g., the boiler) that require the unit to be offline.

Q. Please describe the work to be completed in the 2011 outage at Boardman.

A. 2011 is considered a major outage year because the plant will install new low NOx burners, mercury controls and overfire air ports, replace one third of the boiler convection pass reheater, and install a combustion monitoring system and new boiler cleaning equipment. This work will all be capital work and the outage is expected to last 6 weeks. Major non-capital work that is scheduled to be completed includes the following: rebuild of superheat/reheat temperature control dampers, overhaul of the throttle and governor valves, replacement of a main feed pump volute, inspections of hot reheat elbows, inspections of snubbers for large diameter critical piping, and an air preheater high pressure wash. Additionally, maintenance will be performed on coal handling equipment[3].

2. Gas Plant O&M

Q. Please discuss the changes in gas plant O&M expenditures shown in Table 1 above.

A. Costs for our primary gas plants – Beaver, Port Westward, and Coyote Springs – increase by about $4.8 million from 2008 to 2011.

- Costs at Beaver decrease by approximately $45,000 from 2008 to 2011. Preventative Maintenance costs decrease by almost $500,000 in 2011 related to repairs to the Unit 7 generator rotor in 2008, and further decrease by almost $100,000 due to CT generator inspections in 2008. However, these decreases are offset by increases in IT Services of $200,000, and materials, outside vendor services, and labor, which increase by $200,000. Finally, Personal Protective Equipment costs increase by $100,000 and Clatskanie PUD site electrical and emergency station service supply, oil spill cleanup, and emergency costs, not required in 2008, increase expenses by $50,000.
- Port Westward costs increase by $1.9 million from 2008 to 2011. $0.95 million of the total increase is from the IT Service Provider Allocation – 2010 is the first year that Port Westward is included in the allocation. $300,000 is related to the

[3] Maintenance on coal handling equipment will consist of work on the coal dumper and one of the stacker reclaimers.

repair of the KB Pipeline, and the LTSA account increases by over $200,000 as more maintenance is required when the plant is running longer.

- Coyote Springs costs increase by $2.8 million in 2011. $1.5 million is related to materials and parts for the 2011 maintenance activities, and $500,000 is related to contractors for major maintenance activities outside the GE scope. In corrective maintenance, work to replace the exhaust joints for the Heat Recovery Steam Generator (HRSG) increases costs by $300,000 and combustion inspection labor increases costs by $200,000. The remaining $300,000 increase is due to increases in the IT Service Provider allocation.

Q. PGE has plans to upgrade the turbine at Coyote Springs I during the 2011 outage. If this occurs, will any O&M costs be reduced?

A. Yes. The upgrade itself is discussed in Sections III-C and IV below. If the turbine upgrade is implemented, the $0.3 million expansion joint replacement for the HRSG will not be necessary.

Q. Please explain the Coyote Springs LTSA.

A. PGE has an LTSA with General Electric (GE) for maintenance of the 7F turbines at the Coyote Springs plant. LTSA pricing is based on a fixed cost per quarter (escalated yearly) and a variable cost based on gas turbine hours of operation (“factored hours”, adjusted for mode of plant operation). This pricing method results in O&M costs that vary considerably from year to year.

Q. Is there a mechanism in place to smooth Coyote Springs annual maintenance costs?

A. Yes. PGE established an amortization mechanism in UE 93 that was last updated in UE 180. This mechanism covers major maintenance events at the Coyote Springs plant. The update in UE 180 resulted in an amortization schedule that will not be updated for the 2011 test year. The amortization amount for the 2011 test year is $2.04 million.

Q. What maintenance costs will Coyote Springs incur under the LTSA in 2011?

A. In 2011, Coyote Springs is forecast to operate 6,400 factored hours, resulting in a variable LTSA fee of $4.75 million. In addition, the unit will have operated for 48,000 hours since its last major inspection, at which point the unit's second major inspection (since the original installation of the gas turbine, steam turbine, and generator) is required. This major inspection will result in unusual access to plant components and a scheduled outage of significant duration. This enhanced access is required to perform advanced inspections, along with related work including combustion turbine alignment, exhaust frame modifications, repairs to thrust bearings, the generator stator and the generator field. The cost of these inspections and repairs (approximately $2.0 million) plus the variable LTSA fee, lead to an LTSA amount of $6.8 million for 2011.

Q. Is the $6.8 million included in the 2011 test year?

A. No. Instead, we include a levelized $2.04 million in the test year revenue requirement and reverse the $6.8 million O&M amount in amortization expense. This effectively substitutes the levelized $2.04 million annual collection amount for the $6.8 million O&M amount, thereby reducing the revenue requirement by $4.7 million. Table 1 reflects the $2.04 million figure for each year.

Q. Is all the 2011 maintenance work at Coyote Springs covered under the LTSA?

A. No. The LTSA at Coyote Springs covers a scope of work previously negotiated with GE. The scope includes work generally related to the combustion turbine and other major parts, such as inspections of the steam turbine or combustion parts on the main unit. The additional 2011 expenses are for jobs that fall outside of the LTSA scope, such as cleaning and coating the selective catalytic reduction plates with new catalyst, battery replacement, lube oil and resin replacements, re-engineering of the make-up water demineralizer, and rebuilding cooling tower gear box fan wheels.

Q. Is PGE planning to update the LTSA?

A. Yes. PGE is negotiating an update to the LTSA with GE that will coincide with the plant upgrade in 2011.

Q. What types of maintenance will the new agreement cover?

A. We expect the new LTSA to cover parts, inspections, and maintenance for the gas and steam turbines. Under the preliminary agreement, planned maintenance and unplanned prepaid maintenance will be performed at pre-agreed prices, helping to insulate PGE from rising prices. The agreement will provide for discounts for extra work, include incentives and liquidated damages provisions tied to availability, and require GE to provide both on-site and remote analytical and technical support.

Q. Will there be new provisions in the updated LTSA?

A. Yes. We expect the updated LTSA to have improved coverage of unplanned maintenance costs and collateral damage costs. It is expected to provide increased discounted rates for parts and services for extra work, liquidated damages for parts delivery, coverage for Technical Information Letters, price surety over the life of the contract and on-site, remote monitoring and diagnostics by GE and on site GE representation. We also anticipate re-negotiated payment terms that should result in a smoother year-to-year payment schedule.

Q. What do you expect the payment terms to be under the new agreement?

A. We expect that the amended and restated LTSA will cover the last two payment periods of the original LTSA. As a result, the pricing for those periods should remain unchanged from the original agreement. Beginning in the fourth quarter of 2011 (according to the preliminary agreement), the pricing will adjust to $511 per factored hour (in 2010 dollars, escalated using the same indices currently used in the original LTSA). After the transition to the new pricing method, the large annual swings in maintenance charges that characterized the original LTSA should be eliminated. Annual price changes should result only from the escalation provisions in the contract, which we anticipate to be the same as those in the original contract.

3. Wind Generation O&M

Q. Please explain the changes in wind O&M expenditures shown in Table 1.

A. The increase in wind O&M from 2008 to 2011 is approximately $7.8 million. Most of this increase can be attributed to the full-time operation of all three phases of the Biglow Canyon Wind Farm in 2011 compared to first-phase-only operation in 2008.

Q. What are the major drivers of the increase in Biglow O&M expenses?

A. There are four major drivers of the increased O&M expenses:

- Biglow Service Agreements for Biglow Canyon phases 2 and 3, plus escalation of the Biglow Canyon phase 1 agreement: $6.3 million
- Operations (primarily additional "station service" load for Biglow Canyon phases 2 and 3): $0.6 million
- Environmental Services (compliance with all aspects of Federal and State requirements including wildlife monitoring): $0.2 million
- Increased staffing (4 FTEs) for the two additional phases: $0.2 million

4. Hydro Plant O&M

Q. What are the major components of the changes in hydro O&M expenditures shown in Table 2?

A. The increase in hydro O&M from 2008 to 2011 is approximately $8.4 million. Of this amount, approximately $1.7 million is due to increased environmental services requirements. While we mention these costs in this section, they are more fully explored in Section III-D below.

Table 2 below breaks out hydro O&M between labor and non-labor expenses. The increase in non-labor hydro O&M from 2008 to 2011 is approximately $5.6 million while the increase in labor costs is approximately $2.8 million.

Table 2
Hydro Expenses ($ Millions)

	2008 Actuals	**2011 Test Year**
Hydro O&M Expenses	$11.0	$19.4
Hydro Non-Labor O&M Expenses	6.0	11.6
Hydro Labor Expenses	4.9	7.8
Total Hydro Expenses	**21.9**	**38.8**

Q. Please explain the increase in non-labor hydro O&M expenditures shown in Table 2 above.

A. Most increases in hydro O&M fall into three general categories: hydro licensing requirements (including increases in fees), environmental services, and on-going maintenance projects for the preservation of facilities. We discuss these increases by hydro system, i.e., westside, and eastside projects.

<u>Westside Hydroelectric Project</u>

Four facilities are governed by the new Clackamas River Hydroelectric Project (Clackamas) License: North Fork, Faraday, River Mill Dam, and Oak Grove. The new license establishes operational and other requirements for these facilities that were not in effect in 2008. One of these requirements is participation of the Clackamas River Fish Committee in operational decisions. The Fish Committee is one of the implementation committees for the new Clackamas license. The Fish Committee includes natural resource agencies, tribes, and representatives from environmental organizations. The Fish Committee is involved in the implementation of all fish passage, fish protection, and aquatic measures during the term of the new license.

O&M expenses at River Mill for 2011 are essentially unchanged from 2008. The drivers of cost increases for the other projects are summarized below.

- Faraday - At the Faraday facility, a $0.7 million increase is due to several factors, including $0.4 million to meet new license requirements. Clackamas River Fish Committee support accounts for most of the $0.4 million required to meet license requirements. A $0.1 million increase is due to an increase in the IT allocation to Faraday. IT allocations are discussed in detail in PGE Exhibit 600.
- North Fork - The $0.3 million increase includes approximately $200,000 in incremental maintenance expenses (including $100,000 to dredge the marina area of the reservoir and $88,000 for work on the Migrant Fish Pipe) and $80,000 that represents a portion of the FERC land fee increase.
- Oak Grove - The $3.7 million increase includes $0.4 million to meet license requirements, $2.1 million to meet maintenance requirements, $0.3 million for environmental services, and $1.2 million for increases in rental payments and fees. The $0.4 million to meet license requirements is made up primarily of costs necessary to fulfill new hydro license commitments for protection, mitigation, and enhancement measures at Timothy Lake. The $2.1 million to meet maintenance requirements is composed of lead abatement measures ($2.0 million) and painting projects. The lead abatement project and painting projects are discussed further in Section III-D. The environmental services cost increases are fee increases of $177,000 and professional services cost increases of $150,000. Environmental

services costs at Oak Grove are also discussed in Section III-D. The $1.2 million increase in rental payments and fees is a portion of the FERC land fee increase.

Eastside Hydroelectric Projects

PGE's eastside hydroelectric projects are Round Butte and Pelton. PGE has a two-thirds ownership share in these plants. At Round Butte, a $0.8 million increase in O&M expenses includes $0.1 million for a runner repair and $0.04 million for improved IT data and voice services. The remainder of the increase is located primarily in Environmental Services and is discussed in Section III-D. 2011 O&M expenses at Pelton are essentially unchanged from 2008.

Hydro Labor Expenses

Q. Please explain the changes in hydro labor costs shown in Table 2.

A. Increases in environmental services costs and hydro licensing requirements account for a large proportion of the increase in labor expenses. The environmental service requirements are discussed in Section III-D. Under the new Clackamas license requirements, PGE will now be responsible for the maintenance of the campground previously administered by the Forest Service. This increases PGE labor for Timothy Lake including seasonal and recurring labor, oversight of general maintenance, reservations systems, and supervision of PGE seasonal labor.

5. General Plant O&M

Q. What are the primary reasons for the cost increases in the general plant?

A. Although O&M decreases overall, there are two large increases in this area:

- Preventative maintenance for (DSG) increased by $300,000 from 2008 to 2011, primarily due to addition of more sites and capacity. As discussed earlier, PGE is targeting an additional 15 MW of DSG per year for the next five years. To help mitigate this increase, PGE groups maintenance work together and carefully evaluates bids from several outside maintenance companies. Additional DSG related O&M expenses are included in PGE Exhibit 900, Section V.

- The Portland Harbor Superfund costs increase by approximately $700,000 primarily related to increases in Professional Services to support PGE's interests and fees for the Natural Resource Damage Assessment (NRDA) and the Convening/Allocation process. The purpose of the NRDA is to perform studies to assess damage to natural resources arising from contamination in Portland Harbor. The Convening process involves potentially responsible parties to develop a damages assessment plan and assigns responsibilities to those potentially responsible parties.

6. Power Operations O&M

Q. Power Operations O&M expenditures increase by approximately $0.8 million from 2008 to 2011. What accounts for this increase?

A. Non-labor O&M expenses are essentially unchanged from 2008 to 2011. The increase in labor expense is the result of wage escalation and the addition of four FTEs, two of which are transfers from the Transmission & Reliability Services (T&RS) group and two new FTE positions.

B. FTE Changes

Q. What is the increase in FTEs for plant and power operations?

A. The net increase is approximately 20.

Q. Please summarize the plant and power operations FTE changes from 2008 to 2011.

A. From 2008 to 2011, total FTEs in plant and power operations increase based on new operational needs. As the last of the three phases of the Biglow Canyon Wind Farm becomes operational in late 2010, additional wind technicians will be needed to support the increased generation. The Generation Projects department needs additional specialists to develop and implement project controls related to Biglow Canyon phase 3, Port Westward, and Boardman environmental controls. As we increase our DSG sites, we need to add management and technical support to handle the increasing workload. Park attendants are necessary at Timothy Lake since PGE will assume maintenance responsibility for the recreation site per the requirements of the FERC license for Clackamas.

The Power Supply Engineering Services group, which works on engineering projects at all of our generation sites, requires additional employees to ensure that all labor, work plans, materials, vendors, and project schedules are organized and used efficiently and to focus on wind energy, renewable energy, substation design, protection engineering, and continuous emissions monitoring. PGE will require additional support related to environmental services and environmental compliance requirements, including: Selective Water Withdrawal fish facility operations, Biglow Wind Farm wildlife and oil spill monitoring, Pelton Round Butte protection mitigation enhancement, the sockeye salmon reintroduction plan, fisheries & aquatic programs, and Oregon Department of Environmental Quality (Oregon DEQ) compliance requirements.

C. Capital Expenditures

Q. Please summarize plant related capital expenditures from 2009 to the 2011 test year.

A. Table 3 below summarizes these capital expenditures for 2009, 2010, and 2011. Additional information regarding the timing of the closings is included in the work papers for PGE Exhibit 300.

Table 3
Capital Expenditures ($millions)

	2009 Forecast(1)	2010 Budget	2011 Test Year
Operational Expenditures	$17.7	$21.2	$23.2
Wind: Biglow Canyon phases 2 & 3	398.7	200.6	0
Hydro Relicensing and Construction	26.3	11.8	28.0
Other(2)	8.3	16.4	80.1
Dispatchable Generation	4.0	4.4	4.4
Total	**$455.0**	**$254.4**	**$135.6**

(1) 9 months actual +3 months forecast
(2) Contains costs for Boardman Stator Rewind (2009 only) and Air Quality Controls (2009-2011)

Q. Please explain the major capital expenditures that took place in 2009.

A. The major capital expenditures in 2009 were:

- Biglow Canyon phases 2 and 3 of the Biglow Canyon Wind Farm for $222 million and $176.6 respectively.
- At Colstrip, capital costs of $6.6 million represent PGE's share within the scope of the ownership agreement. Examples of work completed are mercury and NOx controls, cooling tower maintenance, and a turbine-generator overhaul.
- At Boardman, capital costs consisted of $6.7 million to rewind the generator stator and perform generator improvements. The stator rewind was undertaken due to indications of deterioration to the existing stator bars. Generator improvements, including a conversion to water and hydrogen cooled stator bars, were performed in order to extend the life of the generator and improve reliability.

- The bypass stack dampers and foundation at Beaver were replaced totaling approximately $2.0 million.
- A spare generator rotor was purchased for $1.0 million at Boardman. The rotor was purchased in order to mitigate the potential for an extended plant outage upon rotor failure.
- There was $0.9 million of work to upgrade the coal yard programmable logic controller system at Boardman.
- A total of $0.7 million in other thermal fitness capital jobs were completed. These jobs include plant modifications for safety, reliability, and minor upgrades.
- At the North Fork facility, approximately $0.5 million in capital expenses was related to installation of a new liner in the sewage lagoon.
- The CT excitation system at Beaver unit #2 was replaced for approximately $0.3 million.
- $6.3 million of capital expenditures was for approximately 100 additional projects at many of PGE's generation facilities, ranging from $1,000 to $300,000 in size.

Q. Please explain the major expenditures in 2010 and 2011 in Table 3.

A. The major expenditures are:

- Biglow Canyon phase 3 costs were $200.6 million in 2010. The details of the project are discussed in PGE Exhibit 300.
- Capital expenditures for 2010 and 2011 at Boardman include combustion controls, a combustion monitoring system, a boiler cleaning system, and Sulfur dioxide (SO_2) controls. The combustion controls include Low NO_X Burners and Overfire Air ports. PGE also expects capital expenditures related to mercury

controls at Boardman in 2011. These total approximately $16.4 million in 2010 and $80.1 million in 2011[4].

- In 2010, $8.2 million of capital expenses are to replace a turbine at Unit 3 at Colstrip. This represents PGE's share of the generating unit and provides the maintenance to maintain or improve reliability and efficiency within the scope of the ownership agreement.
- In 2010, $3.0 million of expenditures are for thermal fitness. These jobs include plant modifications for safety, reliability, and minor upgrades.
- In 2010, hydro and wind fitness capital jobs totaling $2.3 million are expected to be completed. These jobs include plant modifications for safety, reliability, and other upgrades.
- In 2010, the upper 30% of the boiler reheater at Boardman will be replaced for $2.3 million.
- In 2010, approximately $785,000 is for riparian temperature mitigation on the Columbia River to offset Port Westward wastewater effluent heat load. The mitigation, as mandated by the Oregon DEQ permit, requires the planting of trees on approximately 2 miles of stream bed (roughly 50 acres). Land used to plant the trees is placed into a 40-year conservation easement.
- In 2010, approximately $547,000 is for reliability and safety upgrades to the bus system and station service system at the Oak Grove Plant.
- In 2010 and 2011, approximately $11.8 million and $26.7 million, respectively, are for hydro relicensing activities such as construction and professional services. These are described in more detail below.

[4] This represents 80% of the total cost.

- PGE plans to add 15 MW of DSG capacity per year for the next five years. The cost per additional kW is approximately $290, which equals $4.4 million in 2010 and 2011.

Q. Please explain the hydro relicensing work to be completed in 2009, 2010, and 2011.

A. In 2009, capital expenditures for hydro relicensing and construction are $26 million. This includes $7 million for relicensing construction. In 2010, $12 million for hydro relicensing and construction is expected. The 2010 closings include $6.7 million for relicensing construction. The relicensing costs include professional services (e.g., outside consultants, engineering, research, financial, legal, accounting, and purchasing), AFUDC, direct labor, and tax and license fees associated with our Oak Grove and North Fork hydro facilities. In 2011, capital expenditures for hydro relicensing and construction is $28 million. The 2011 expenses include $13 million for relicensing construction and $9 million for the River Mill Downstream Migrant Surface Collector.

Q. Which strategic projects are closing prior to the end of 2011?

A. We expect $535.6 million of projects to close to plant during 2010 and 2011. These projects include Biglow Canyon phase 3, Clackamas relicensing, and Low NOx Burners, Mercury and SO_2 controls at Boardman. A discussion of rate base, including capital additions, is in PGE Exhibit 300.

Q. Please describe the Clackamas relicensing costs that close to plant in 2010.

A. $65.6 million for Clackamas relicensing will close to plant by December 2010. The relicensing costs include professional services (e.g., outside consultants, engineering, research, financial, legal, accounting, and purchasing), AFUDC, direct labor, and tax and license fees associated with our Oak Grove and North Fork hydro facilities. As discussed below in Section IV, we expect to receive the license in mid- to late-2010; however, for revenue requirement purposes we have made an assumption that these costs do not go into service until December 2010.

Q. What is the purpose of the Low NOx burners, mercury and SO_2 controls at Boardman?

A. The Oregon Regional Haze Rule requires installation of the Low NOx burners by July 2011. NOx emission limits will be reduced by 50% in 2011. The purpose of the Low NOx burners and Overfire Air ports is to achieve the required NOx levels of less than 0.23 lb / MMBTU (annual average) and 0.28 lb / MMBTU (30-day average).

The mercury controls project will install a sorbent injection system upstream of the currently operating electrostatic precipitator (ESP). Mercury will be adsorbed onto the sorbent material and captured by the ESP before it can be released to the atmosphere. The Oregon Utility Mercury Rule requires mercury controls to be installed and operating by July 2012. Per this rule, PGE will need to reduce the level of mercury emissions by 90% or less than 0.6 lbs/TBTU.

The SO_2 controls project will install a semi-dry flue gas desulfurization system which would cut SO_2 emissions by 12,000 tons per year for an 80 percent reduction. These controls must be installed by July 2014, and are not included in the 2011 test year ratebase.

Q. Is PGE planning any plant upgrades at Coyote Springs in 2011?

A. Yes. PGE is planning a major upgrade to Coyote Springs that will include a new compressor rotor, blades, vanes and casings, new turbine rotor, 7241 buckets, nozzles and casings, new Dry Low NOx (DLN) Model 2.6 combustion system, new casing temperature management system, and new cooling optimization package. This upgrade will result in both increased capacity and an improved heat rate. A new Mark Ve control system will also enhance system control capabilities. PGE's customers will realize significant system generation cost savings as a result of the upgrade. The benefits of the Coyote Springs upgrade are also discussed in PGE Exhibit 200.

Q. What is the total cost of the Coyote Springs upgrade?

A. The total cost included in revenue requirement of the upgrade is $27.2 million.[5]

Q. What are the net system benefits of the Coyote Springs upgrade?

A. The estimated present value of the net benefits over the lifetime of the operation of the plant is $80 million. System benefits resulting from the upgrade include avoided equipment replacements, maintenance agreement savings and the value of increased generation and improved efficiency (i.e., lower heat rate). The economic analysis demonstrating the positive net present value for this upgrade is included as confidential PGE Exhibit 703C.

Q. Could system benefits from the Coyote upgrade be even greater?

A. Yes. The agreement with the contractor includes incentives for achieving greater increases in plant capacity and bigger improvements in plant heat rate. The $80 million net present value figure does not include the benefits and costs associated with these possible increases in system performance.

Q. Is the Selective Water Withdrawal (SWW) project complete?

A. Yes. The SWW was substantially completed and all major components were connected on December 3, 2009. A settlement was reached among the parties and was approved by the OPUC on January 22, 2010 (Order No. 10-020). PGE has tested the facility and as of January 20, it was closed to plant and rates went into effect February 1, 2010.

[5] This amount is a preliminary estimate and does not include $3.7 million in contingency costs because of time constraints.

D. Environmental Services

Q. Why are you discussing Environmental Services in the Generation testimony?

A. Environmental Services (ES) provides general support to all PGE facilities, including generation. Some examples of the activities are monitoring of wildlife, fisheries, air quality and waste management/disposal. In addition, ES has experienced significant charges in the past several years that are likely to further escalate and are discussed in detail later in this testimony.

Q. What is PGE's forecast for environmental costs in 2011?

A. PGE is forecasting environmental costs to be $6.5 million, which represents an increase of $3.2 million since 2008. The costs consist of project specific costs and general Environmental Services support (A&G) related to PGE's various generation facilities. Table 4 below provides a summary of environmental costs for both categories.

Table 4
Environmental Costs
(000s)

	2008 Actuals	**2011 Forecast**
Pelton Round Butte	$746.0	$2,210.8
Generation Support	856.3	1,489.3
Cleanup Projects	623.2	1,611.9
Miscellaneous	1,026.5	1,226.1
Total Environmental Services Costs	**$3,252.0**	**$6,536.1**

Q. Why have costs increased?

A. There are three major components of the increase, each of which will be discussed in more detail later in this testimony. The first component is the Pelton Round Butte projects. PGE is required as part of FERC relicensing of Pelton-Round Butte to complete various projects, which account for $1.4 million of the increase.

The second component is related to three environmental cleanup projects: Portland Harbor, Oak Grove, and Harbor Oil. Costs have increased $1 million since 2008 to $1.6 million. Activities associated with these projects will continue to intensify beyond 2011.

The third component is related to Environmental Services general support at PGE's generation facilities. In 2011, generation support costs are expected to be $1.6 million, an increase of $0.5 since 2008.

1. Pelton-Round Butte Projects

Q. What is forecasted in 2011 for the Pelton-Round Butte projects?

A. As shown in Table 5 below, we are forecasting $2.2 million, an increase of $1.4 million since 2008.

Table 5
Pelton Round Butte Projects
(000s)

	2008 Actuals	**2011 Forecast**
Fishway Pathways	$125.3	$1,015.3
Round Butte Hatchery	353.1	442.3
Fish Health Funding	-	207.3
Deschutes River Gravel Study	45.2	194.5
Terrestrial Resource Mgt	71.4	142.0
Miscellaneous	151.0	209.4
Total	**$746.0**	**$2,210.8**

Q. Please describe the projects at the Pelton and Round Butte hydro facilities.

A. PGE has completed the Selective Water Withdrawal in the forebay at Round Butte Dam. It is designed to capture downstream migrating juvenile salmon and steelhead from the Crooked, Metolius, and upper Deschutes rivers, which will then be trucked around the three dams and released into the lower Deschutes River for the first time since 1968. In addition, we perform ongoing activities, such as monitoring fish and wildlife, water quality, and hazardous waste management and disposal. Five significant projects include: 1) Section 18 Fishway Pathways and Lamprey Studies, 2) Fish Facility Operations (Round Butte

Hatchery), 3) ODFW Cooperative Agreement / Fish Health Funding, 4) Lower Deschutes River Gravel Study, and 5) Terrestrial Resource Management Plan.

Section 18 Fishway Pathways and Lamprey Studies

Q. Please describe the Fishway Pathways and Lamprey Studies.

A. The Fishway Pathways and Lamprey Studies implement the fish passage (section 18 prescriptions) issued by the U.S. Fish and Wildlife Service (USFWS) and National Oceanic and Atmospheric Administration (NOAA) Fisheries. Prescription 1 issued by each federal agency requires PGE to implement the Fish Passage Plan. This plan includes the construction of new or reconstruction of historic fish passage facilities at Round Butte, Pelton, and the Regulating Dams. After completion, additional fishway prescriptions require that these facilities be tested, and then operated. Successful operation is measured by the proportion of anadromous salmon and steelhead smolts that enter the reservoir from the tributaries and are safely captured and transported around the hydro project. Pursuant to Prescription 18, USFWS requires the completion of a Pacific Lamprey passage evaluation and mitigation plan. This plan was approved by FERC on November 8, 2006 and is now being implemented.

Round Butte Hatchery Project

Q. Please describe the Round Butte Hatchery Project.

A. The FERC License directs PGE and the Confederated Tribes of Warm Springs (Tribes) to enter into an agreement with ODFW for the operation of Round Butte Fish Hatchery at no more than the current production levels of spring Chinook and summer steelhead during the term of the license. This agreement was approved by FERC in September 2006. The requirement to operate new and/or reconstructed fish passage facilities at Pelton Round Butte on a year-round basis has been the primary factor for increased costs projected for the

Section 18 Fishway Pathway program in 2010 and 2011. Another factor contributing to increased costs is the FERC license requirement to conduct several test and verification studies to evaluate the effectiveness of new fish passage facilities and the fish passage program. A majority of these operating costs had previously been capitalized prior to completion of the SWW and new fish passage facilities.

Fish Health Funding Project

Q. Please describe the ODFW Cooperative Agreement / Fish Health Funding Project.

A. The FERC license directs PGE and the Tribes to enter into an agreement with the ODFW to fund two positions. One of these positions is a Mitigation Coordinator, the other a Fish Health Specialist. PGE and the Tribes are required to develop and file with FERC a plan for a Fish Health Management Program (the Program) at Pelton-Round Butte. The Program will support the fish passage effort, monitor disease incidence in Deschutes River fish populations and potential changes in the distribution of fish disease agents. This Program was approved by FERC on January 31, 2007. The program provides for the evaluation of disease as a mortality factor in downstream and upstream migrating anadromous salmonids and procedures needed to reduce the risk of transmitting pathogens upstream of the Project. Projected costs increase in 2010 and 2011 because we were able to capitalize charges in 2008.

Lower Deschutes River Gravel Study

Q. Please describe the Lower Deschutes River Gravel Study.

A. The FERC License required PGE to first file and then implement a plan to evaluate gravel mobility, supply, and use by spawning salmonids in the lower Deschutes River from the Reregulating Dam to Trout Creek confluence. This project implements the lower river gravel study plan, which has a sediment transport monitoring component, an experimental gravel augmentation component, and a biological (fish use) component.

<u>Terrestrial Resource Management Plan</u>

Q. Please describe the Terrestrial Resource Management Plan.

A. The FERC License directs PGE to develop, file, seek approval, and implement a Terrestrial Resources Management Plan (TRMP). The TRMP is the principal instrument for management of, implementation, monitoring and adaptation of Protection Mitigation and Enhancement Measures for terrestrial resources affected by or related to the hydro Project. The TRMP was approved by FERC in November 2006 and implemented in 2009.

2. Environmental Cleanup

Q. Please describe the cleanup activities PGE is undertaking.

A. PGE is involved with three environmental cleanup projects at this time. Two of the sites are Environmental Protection Agency (EPA) designated Superfund Sites: Portland Harbor and Harbor Oil. The third site is at PGE's Oak Grove facility, located on U.S. Forest Service land. The Oak Grove facility has two components: 1) Polychlorinated biphenyl (PCB) cleanup, and 2) lead abatement at identified pipe trestles.

Q. What is the forecasted environmental cost increase for Portland Harbor, Harbor Oil, and Oak Grove from 2008 to 2011?

A. We are forecasting an increase of $970,000 from 2008 to 2011 for Environmental Costs. The remediation of Oak Grove is budgeted separately. Aside from the Oak Grove cleanup costs, the majority of the increase is related to the Portland Harbor project, which includes the Downtown Reach section. Table 6 below summarizes the costs of each of these projects in 2008 and 2011. These represent investigation costs (except for Oak Grove) only and do not include remediation or actual cleanup costs.

Table 6
Cleanup Costs
(000s)

	2008 Actuals	2011 Forecast
Portland Harbor	$496.9	$1,212.4
Harbor Oil	126.3	65.1
Oak Grove	0.0	334.4
Environmental Costs	**$623.2**	**$1,611.9**
Oak Grove remediation	10.0	2,044.2
Grand Total	**$633.2**	**$3,656.1**

We discuss these three projects below.

<u>Portland Harbor</u>

Q. Please describe the Portland Harbor project.

A. The Portland Harbor Superfund Site (Portland Harbor) currently extends from approximately mile 2 through mile 12 of the Willamette River[6]. The EPA began an investigation of the site in 1997, and based upon that investigation, initially sent "Notices of Potential Liability" to 69 parties, including PGE, formally identifying them as Potentially Responsible Parties (PRPs) under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA).[7] There are now hundreds of parties under investigation and the EPA has assigned formal PRP status to approximately 80 parties. A small portion of these PRPs (approximately 10) formed the Lower Willamette Group (LWG) and are concluding a Remedial Investigation (RI) of the site and are conducting a Feasibility Study (FS). PGE did not wish to incur significant up front costs and perform the RI/FS and, thus, is not a party to the LWG agreement. Although costs associated with an RI/FS must be borne by all PRPs, getting other parties to contribute must be accomplished

[6] For additional detail, the United States Environmental Protection Agency has posted the map in Exhibit 1 at http://yosemite.epa.gov/R10/CLEANUP.NSF/ph/Uplands/$FILE/Portlandharbormaplg.jpg
[7] The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), commonly known as Superfund, was enacted by Congress on December 11, 1980. This law created a tax on the chemical and petroleum industries and provided broad Federal authority to respond directly to releases or threatened releases of hazardous substances that may endanger public health or the environment.

through an allocation[8] process or through expensive contribution litigation. The estimate for RI/FS costs incurred so far is $75 million and will be allocated among the PRPs in the future; a specific date is not known at this time.

EPA's investigations indicate the presence of polychlorinated biphenyls (PCBs), a chemical used in various types of electrical equipment including transformers, at the Portland Harbor site. For this reason, in January 2008, the EPA served PGE with a formal information request[9] that included more than 80 questions regarding "any Property you currently own, lease, operate on, or otherwise are affiliated or historically have owned, leased, operated on, or otherwise been affiliated with" from 1937 to the present, within approximately 800 feet of the Willamette River between River miles 2 through 16. PGE has operated since the 19th century on numerous properties in the area identified by the 104(e) Information Request. PGE has prepared and submitted responses to the EPA's requests.

Under CERCLA, PGE's potential liability as a PRP includes claims for site assessment costs, cleanup costs, damages to natural resources, state and federal oversight costs, and remediation and restoration costs. PGE is actively participating in developing and implementing possible settlement proposals that would divide the cost of investigating and remediating the site among all the participating PRPs. We expect this process to take several years. It has involved, and will continue to involve, substantial costs associated with internal investigations, documentation generation and evaluation, the hiring of consultants and other contractors to assist in complying with EPA and Oregon DEQ procedures, internal administration, and legal representation in the CERCLA PRP liability allocation negotiations.

---

[8] PRPs typically will engage in a voluntarily settlement process to allocate remediation cost and performance responsibility. This process, known as an "Allocation", usually involves hiring an Allocator who will aid the parties in determining how to apportion the costs among themselves.

[9] This request was pursuant to CERCLA Section 104(e) (a "104(e) Information Request").

Q. What is PGE's involvement in Downtown Reach?

A. Downtown Reach includes river miles 12 through 16 of Portland Harbor and is currently regulated by the Oregon DEQ. The Oregon DEQ has issued PGE a unilateral order requiring participation in the evaluation and possible cleanup of particular areas in the Downtown Reach. The process will involve site assessments and river sampling with possible remediation required in the uplands and in the river.

Q. What processes are currently in progress?

A. For Portland Harbor, the LWG is in the process of conducting the RI/FS for Portland Harbor. PGE expects the LWG to complete a draft RI in early 2010. A final RI is expected in Fall 2010. PRPs, including PGE, are currently in the process of selecting an Allocator, and with candidate interviews having been conducted. Due to lack of consensus in the LWG, the Allocator position has not yet been filled.

Q. What are the next steps in the process?

A. After a draft of the Feasibility Study is submitted in Fall 2010 and once EPA settles on a final remedy, it will issue a Record of Decision (ROD), which we expect in June 2012. The ROD will indicate EPA's areas of concern, the types of remedial actions EPA expects to be implemented, and the contaminant level at which these areas would be considered remediated.

In the meantime, PRPs are working through the allocation process. Once an Allocator is selected, parties will share 104(e) information request responses and begin allocation discussions. PGE currently expects an Allocation Report to be generated by the Allocator in May 2012. Then, PRPs will resume discussions and submit a good faith offer to EPA, probably in the Fall of 2012. Consent Decree negotiations are expected to begin the following spring with a Consent Decree entered by EPA in December 2013. The Consent

Decree will indicate which PRPs are responsible for performance of the remedy, and will likely specify their allocation of the remediation costs.

Q. Does PGE have control over the timing of these processes?

A. No. PGE is one of many PRPs and is not a member of the LWG. The EPA and LWG are dictating the pace.

<u>Oak Grove</u>

Q. Please describe the Oak Grove project.

A. PGE operates the Oak Grove facility, which is located on federal lands administered by the Forest Service, pursuant to a FERC license. In August 2005, PGE retained environmental consultants to perform a site investigation of potential petroleum contamination discovered near the maintenance shop at the Oak Grove facility. The site investigation was conducted in five phases between August 2005 and April 2008. The consultants discovered petroleum contamination in the area of the maintenance shop, which PGE has remediated. The consultants also discovered PCB contamination downhill of a storm water outfall near the maintenance shop. The contamination appears to be limited to surface soils and does not extend to the nearby Clackamas River.

In April 2008, the Forest Service notified PGE that Forest Service oversight and approval of any cleanup under a mutually negotiated "Settlement Agreement and Administrative Order on Consent" (AOC) would be required before cleanup could commence. The Forest Service issued a 104(e) Information Request to produce all documents and certain information related to the Oak Grove PCB spill. On July 11 and August 9, 2008, PGE submitted information and documents to the Forest Service.

Additionally, on September 17, 2008, PGE sent formal notification to the U.S. Forest Service of potential lead contamination of the area under the Cripple Creek, Pint Creek, and

Canyon Creek support trestles. In 1968, 1970, and 1971 PGE sandblasted the trestles (one per year) in preparation for re-painting, and then re-painted the trestles in accordance with Oregon DEQ protocols in place at the time. In June 2005, PGE began preparation to again re-paint the trestles. However, in the process of preparing the trestles, soil testing was conducted to ensure the painting company was not contributing to any previous contamination in the area. PGE and an environmental consultant took soil samples, which were then analyzed for eight Resource Conservation and Recovery Act (RCRA) heavy metals. Testing confirmed that several samples exceeded the limit levels for Arsenic, Cadmium, Chromium, Lead, and Silver.

Q. What processes are currently in progress and what are the next steps?

A. Regarding the PCB cleanup, PGE has completed the Engineering Evaluation/Cost Analysis (EE/CA) for the site and submitted the results to the Forest Service. PGE expects to cleanup the site in summer 2010.

Regarding lead contamination, PGE has notified the Forest Service and is waiting for its determination on the site for cleanup protocol. PGE expects the Forest Service to require resolution of the lead contamination issue in a comprehensive Administrative Order on Consent (AOC) under CERCLA. PGE anticipates further investigation in 2010 and cleanup activities to occur in 2011. The cost of the cleanup ($2 million) is included in the Oak Grove O&M expenses as shown in Table 6 above.

Harbor Oil

Q. Please provide some background on the Harbor Oil project.

A. Harbor Oil, Inc. (Harbor Oil), an oil re-refiner located in north Portland, was utilized by PGE to process used oil from our power plants and electrical distribution system from at least 1990 until 2003. Harbor Oil was also utilized by other entities for the processing of used oil and other lubricants.

In 1974 and 1979, major oil spills occurred at the Harbor Oil site that impacted an approximately two-acre area. Elevated levels of contaminants, including metals, pesticides, and PCBs, have been detected at the site. On September 29, 2003, Harbor Oil was added to the federal National Priority List as a federal Superfund site.

PGE received a Special Notice Letter for RI/FS from the EPA, dated June 27, 2005, in which PGE was named as one of 14 PRPs with respect to the Harbor Oil site. The letter started a period for the PRPs to participate in negotiations with the EPA to reach a settlement to conduct or finance an RI/FS of the Harbor Oil site. On May 31, 2007, an Administrative Settlement Agreement and Order on Consent was signed by the EPA and six other parties, including PGE, to implement an RI/FS at the Harbor Oil site. The final revised work plan for the RI/FS has been submitted to the EPA, and phases 1 and 2 of the site characterization are complete.

Q. What processes are currently in progress and what are the next steps?

A. Risk assessments for human health and ecological risks are in progress. The RI report is scheduled to be submitted to EPA in 2010. The Feasibility study is scheduled to be completed in 2011. Once the RI/FS is completed, EPA will provide a ROD to all parties identifying the remedy and costs.

Q. What is PGE's forecast for the remaining costs for this project?

A. PGE's preliminary forecasts for 2010 and 2011 are included in Confidential PGE Exhibit 102. These amounts are based on known and measurable costs but do not include the potentially significant costs associated with additional investigation, allocation, and remediation.

3. General Support at Generation Facilities

Q. Please describe some of the activities that Environmental Services performs at various PGE plants.

A. Table 7 below shows environmental costs at PGE's generating facilities.

Table 7
Environmental Costs by Entity
(000's)

	2008 Actuals	2011 Forecast
Hydro Facilities	$389.7	$705.4
Biglow	247.6	557.8
Boardman	127.9	81.4
Beaver	12.6	74.1
Port Westward	52.1	17.9
Miscellaneous	26.4	52.8
Total	**$856.3**	**$1,489.3**

At Biglow Canyon Wind Farm, we are required by federal and state agencies (FERC and Oregon Energy Facility Siting Council-EFSC) to monitor wildlife and help manage hazardous waste and disposal issues. These costs increase because all phases of Biglow Canyon are expected to be operating in 2010 and 2011.

At PGE's Clackamas hydro facility, we are expecting a license early 2010 and there will be several projects to do as a condition of the re-license.

At the Boardman plant, PGE has been working with state and federal regulators over the past three years to adopt a plan to reduce emissions from the plant. We continue to work closely with the OPUC, Oregon DEQ, and interested stakeholders as we discuss the fate of the Boardman facility. Other activities include fish and wildlife activities, water quality monitoring, and hazardous waste management and disposal.

At Port Westward, we are required by the federal (FERC) and state agencies (EFSC) to monitor wildlife (bald eagle nests), air quality, water quality, emissions, and temperature mitigation. We also assist with hazardous waste disposal issues.

The new FERC license for the Clackamas Project will require a significant increase for implementing aquatic projects and evaluating new fish facilities to ensure they meet protection standards.

4. True-up Mechanism

Q. Environmental Services expects to spend $6.5 million in 2011, yet there are several Superfund sites included whose timing and funding is uncertain. How does PGE propose to mitigate this uncertainty?

A. PGE proposes a balancing mechanism that would track variances from Superfund (or Superfund-like) projects included in a balancing account.

Q. What type of projects would be included in the balancing account?

A. PGE's proposed balancing account mechanism would include only those projects where PGE has been identified as a responsible party by a federal or state agency. These projects would be Portland Harbor, Harbor Oil, and Oak Grove (Lead Abatement and PCBs). Portland Harbor and Harbor Oil are declared by the EPA to be Superfund Sites. Although Oak Grove is not a Superfund Site, it has Superfund-like characteristics.

Q. How would the balancing account work?

A. The baseline amount would be included in the test year. The balancing account would track differences between actual and forecasted costs. Any amounts accrued in the balancing account would earn interest at PGE's cost of capital and would be subject to a prudence review and/or audit.

Q. How often would the balancing account be reviewed?

A. The account would be reviewed at the time of a general rate case or at least every two years.

Q. What are the benefits to customers of this balancing account mechanism?

A. Environmental projects can sometimes take decades to resolve. During this time, it is very difficult to accurately forecast costs and potential insurance proceeds received that offset these costs. The balancing account minimizes volatility by enabling PGE to track actual costs versus forecasts, and review (and reset, if necessary) the account on a regular two-year cycle.

IV. Cost Efficiency in Generation

Q. Has PGE implemented cost efficiency programs in the generation plants?

A. Yes. As summarized in PGE Exhibit 200, PGE has taken several steps toward cost savings and cost efficiency in the generation plants.

- Union Contract Negotiation: Although unions usually limit a worker's job description, in its most recent 3-year contract with IBEW Local 125, PGE negotiated to expand the roles and responsibilities of Port Westward and Coyote Springs union employees. Thus, instead of hiring additional workers to complete extra tasks, PGE can assign those tasks to existing employees. This keeps our workforce leaner and reduces hiring, labor, and labor related costs.
- Biglow Warehouse Heating: In the coldest winter months, the cost to heat the Biglow warehouse with propane averaged $600-900 per week. The Biglow staff teamed up with PGE's Power Supply Engineering Services to install a waste oil burner in early 2009, which burns used motor oil and waste oil from the turbines. The system will not only pay for itself in less than four years, but is also an environmentally safe and friendly way of disposing of the waste oil.
- DSG: By the end of 2010, PGE will have 31 DSG sites with a total capacity of 75.2 MW. These resources are most useful during extreme temperature changes and emergencies, when PGE's system is under strain and provides needed reserves. To meet the load without these DSG sites, PGE would be forced to buy power in the market, and when demand is high and supply is low, prices escalate quickly. Therefore, the DSG sites provide low-cost power when PGE customers need it most.

- Turbine upgrade at Coyote: As discussed above in Section III-C, this 2011 upgrade will increase the efficiency of operations at the Coyote plant. The upgrades include:
  - A new compressor and turbine rotor
  - Higher temperature nozzles, blades and seals for the power turbine
  - New compressor and turbine casings
  - A new dry low NOX combustion system
  - A Mark Ve control upgrade

  These upgrades will result in 15MW of additional capacity and an improved heat rate. The upgrades will reduce inspection requirements, extend the life of the rotors, and promote more reliable operation. The new control system permits a larger plant operating range and more dispatch flexibility which can aid in the integration of wind resources into the PGE system. This project was discussed above in Sections III-A-2 and III-C.
- Generation Excellence: In 2006, PGE started the Generation Excellence program, which focuses on plant efficiency, reliability, and continuous improvement. A major part of this program is Reliability Centered Maintenance (RCM), which works to increase plant availability and reliability through optimized planned maintenance. Once plant management identifies critical systems with frequent failures or costly reactive maintenance, the RCM group can begin a study of the system's operation and maintenance to determine the optimal preventative maintenance schedule. Through the analysis of critical plant components, we are able to optimize the maintenance for these systems, reduce breakdowns and increase reliability and availability. By reducing breakdowns that lead to forced

outages, we also reduce replacement power costs – PGE is not forced to buy from the wholesale market when a plant is suddenly unavailable.

Q. Has the RCM program identified specific preventive maintenance projects that led to savings?

A. Yes. There are several examples of RCM success in the past few years.

- In 2006, RCM analysis was performed on the sootblower system and the pulverizers at the Boardman coal-fired plant. The sootblowers use water and steam to clean the ash that adheres to the tube surfaces. The ash build up on the tube surfaces affects heat transfer and the efficiency of the system. The analysis of the system caused us to increase the number and frequency of inspections, catch potential failures before they occurred, improve performance and reduce corrective maintenance costs.
- The pulverizer grinds coal into a fine powder for combustion in the boiler – an important part of the generation process. The analysis helped us to identify the maintenance activities that would prevent the most common failures in the pulverizers. In 2007, the labor and material costs for the pulverizers between January and July were about $350,000. In 2009, the same costs in the same period were much lower, approximately $100,000.
- The RCM group performed an analysis on the reheater section of the boiler at Boardman. A reheater leak can take the plant offline for up to four days, costing the plant as much as $2 million, or $500,000 per day in replacement power alone. Through the RCM analysis, we were able to forecast expected reheater tube leaks in the coming years and make a cost-effective decision to replace the upper section of the reheater.

Q. How expansive is the RCM program?

A. As of early 2010, RCM analysis has been performed on generation equipment at seven different plants, in addition to the sootblower and pulverizer at Boardman. At Port Westward, RCM has been used to analyze the circulating water system, the feedwater system, the wastewater system, the gas turbine lube oil, and the heat-resistant steam generator. At Coyote Springs, studies have been performed for the gas turbine, the gas turbine auxiliaries, and the ammonia system. RCM has also analyzed the 4160V breakers at the Beaver Plant. At Westside Hydro, RCM analysis has been performed on Units 1 and 2 at North Fork, and Units 1 and 2 at Oak Grove. Finally, the RCM group analyzed Round Butte Units 1, 2, and 3.

V. Hydro Relicensing Update and Related Revenue Requirement

Q. What is the status of the relicensing process for PGE's hydro projects - Willamette Falls, Pelton Round Butte, and Clackamas?

A. PGE has obtained FERC licenses for the Willamette and Pelton Round Butte projects, and is in the process of obtaining a long-term license for the Clackamas projects.

Q. What is the status of PGE's Clackamas Project relicensing process?

A. We received a Water Quality Certification for the Clackamas River in June 2009. This is one of the final steps before a new license can be issued. We anticipate a FERC-issued license for the Clackamas projects in mid-2010.

Q. What licensing structure supports operation of the Clackamas Project prior to issuance of a new long-term license?

A. The four facilities included in the Clackamas Project were previously covered by two separate long-term licenses for the Oak Grove and North Fork Projects. These licenses expired on August 31, 2006. An "annual license" allows the four plants to continue operation under the terms of the Oak Grove and North Fork Project licenses while FERC considers the new long-term Clackamas Project application.

Q. Do the hydro O&M expenses you discussed in Section III-A-4 of your testimony include costs associated with protection, mitigation, and enhancement measures required by the new long-term licenses?

A. Yes. For example, the hydro O&M figures in Table 1 above include costs required for Fish Committee support at Faraday and protection, mitigation and enhancement measures at Timothy Lake.

Q. At the time PGE decided to pursue new long-term hydro licenses, OPUC Order No. 89-507 governed the integrated resource planning process. This order directed utilities

to consider both cost and risk in their resource decisions. Do PGE's hydro relicensing decisions meet the Order No. 89-507 criteria?

A. Yes. With respect to expected costs, PGE's UE 180 testimony, PGE Exhibit 300, Section III (included as PGE Exhibit 704) explained that the estimated costs of relicensing hydro resources compared very favorably to the costs of other alternatives at the time PGE decided to seek new long-term licenses. With respect to risk, relicensing compares very favorably with other alternatives. The costs incurred to meet the license conditions will almost all be fixed, whereas the costs of other resource alternatives will be subject to much more variation over time – changing market electric prices, changing fuel prices, possible changes related to CO_2 standards, etc.

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. Ms. Behbehani, please describe your qualifications.

A. I received a Bachelor of Science degree in Architectural Engineering from Roger Williams University in 1982, and am enrolled in the Master of Business Administration program at Marylhurst University. I have worked on Nuclear, Coal, Gas, Hydro and Wind facilities for almost my entire career. In 1997, I joined PGE as a Civil Engineer in Power Supply Engineering and began serving as Manager of Environmental Services in 2007.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
701	Generating Resource Summary
702	IR and PTP Transmission Resource Summary
703C	**Coyote Turbine Upgrade Economic Analysis – Confidential**
704	Section III of PGE Exhibit 300 in Docket UE 180

PGE's 2011 Supply Resources		Annual Energy (2) (MWa)	January Capacity (1) (MW)
Type	**PGE Resources**		
Coal	Boardman	297	375
Coal	Colstrip	258	296
Gas	Beaver	41	521
Gas	Beaver 8	0.103	24
Gas	Port Westward	284	425
Gas	Coyote Springs	168*	247*
Wind	Biglow Canyon Wind Project I (3)	48	6
Wind	Biglow Canyon Wind Project II (4)	54	7
Wind	Biglow Canyon Wind Project III (5)	60	9
Hydro	Oak Grove	26	33
Hydro	North Fork	23	43
Hydro	Faraday	20	43
Hydro	River Mill	12	23
Hydro	Sullivan	14	16
Hydro	Round Butte	77	225
Hydro	Pelton	34	73
Total	**PGE Plants**	**1,248**	**2,366**
Type	**Contracts**		
Hydro	Wells	85	147
Hydro	Rocky Reach	72	137
Hydro	Grant PUD Deal	125	134
Hydro	Portland Hydro	10	36
Wind	Iberdrola's Klondike II	26	19
Wind	Vansycle Ridge	8	1
Solar	ProLogis/SunWay 2 LLC	0	0
Capacity	Spokane Energy Capacity	0	150
Capacity	EWEB Capacity	0	10
Other	Glendale Sale	(10)	(15)
Exchange	City of Glendale Exchange (6)	0	30
Exchange	Chelan Exchange (7)	(2)	0
Hydro	Canadian Entitlement Ext.	(14)	(18)
Hydro	Wells Settlement Agreement	14	0
Other	TransAlta	93	100
Other	Covanta PURPA Contract	10	10
Capacity	Dispatchable Standby Generation (DSG)	0	53
Total	**Longer-term Contracts**	**417**	**622**
	Total Resources	**1,665**	**2,988**

(1) Capacity measures are for January. Note that the capacities of gas-fired plants are inversely related to temperature. Figures for Boardman, Colstrip, Pelton, and Round Butte are PGE shares.

(2) Theoretical Annual Average Availability Using Average Hydro

(3) Biglow I has 125.4 of namplate capacity.

(4) Biglow II has 149.5 of namplate capacity.

(5) Biglow III has 174.8 of namplate capacity.

(6) The City of Glendale Exchange provides 11 MWa of energy during November-February winter seasons in exchange for similar obligations from PGE to Glendale during June-September summer seasons.

(7) The Chelan Exchange provides 50 MW of summer capacity.

* The turbine upgrade at Coyote Springs will increse both the annual energy and capacity to 178 Mwa and 262 MW.

PGE's Contract Summary

PTP Contracts

Point of Receipt	Max Capacity (MW)	Term	Point of Delivery
Biglow Canyon	300	Expires 9/2015 with roll-over rights	PGE System
Biglow Canyon	150	Expires 6/2015 with roll-over rights	PGE System
Big Eddy	100	Expires 9/2015 with roll-over rights	PGE System
Mid-C Remote *	600	Expires 6/2015 with roll-over rights	PGE System
Federal System (Vansycle Ridge)	25	Expires 11/2016 with roll-over	PGE System
Total PTP (before IR conversion)	1175		

PTP Contracts resulting from IR conversion

Point of Receipt	Max Capacity (MW)	Term	Point of Delivery
Beaver **	531	Expires 1/1/2015 with roll-over rights	PGE System
Coyote Springs **	250	Expires 1/1/2015 with roll-over rights	PGE System
Garrison - Colstrip **	270	Expires 1/1/2015 with roll-over rights	PGE System
Boardman **	379	Expires 1/1/2015 with roll-over rights	PGE System
Mid-C Remote *	169	Expires 1/1/2015 with roll-over rights	PGE System
Mid-C Remote *	131	Expires 1/1/2015 with roll-over rights	PGE System
Mid-C Remote *	161	Expires 1/1/2015 with roll-over rights	PGE System
Mid-C Remote *	27	Expires 1/1/2015 with roll-over rights	PGE System
Mid-C Remote	100	Expires 1/1/2015 with roll-over rights	DC Intertie - Big Eddy
Mid-C Remote	177	Expires 1/1/2015 with roll-over rights	AC Intertie - John Day
Mid-C Remote	23	Expires 1/1/2015 with roll-over rights	AC Intertie - John Day
Total IR converted to PTP	2218		

* Up to 788 MW of Mid-C remote to PGE's system is available to dynamicly schedule PGE's Mid-Columbia resouces to load
Mid-C resouces includes Wanapum, Wells, Priest Rapid, Rocky Reach and Washington Water Power (Spokane Energy)
** Capacity available to dynamicaly schedule the resouce to load

Exhibit provided by Jerry Thale

III. Hydro Relicensing

A. Introduction

Q. Why are you addressing hydro relicensing in this filing?

A. The 2007 test year is the first to include costs related to this effort, which PGE began in 1995. This test year includes some O&M associated with new licensing requirements, as well as some capital expenditures, including those associated with obtaining new licenses for Pelton, Round Butte, and Sullivan. Our new licenses will require capital expenditures of approximately $370 million. Although we have already incurred some of these costs, most are for activities that will occur between now and 2020. O&M expenses will also increase. Using a collaborative process, however, we preserved the cost-effective status of these resources and avoided any significant decrease in their performance. The latter is important because, at zero variable fuel cost, production capability is the key to the value of these resources.

Q. How is this section organized?

A. Part B summarizes the hydro projects PGE decided to relicense and the related costs, test year revenue requirement, and measures of cost effectiveness. Part C describes the approach to relicensing that PGE took under the Federal Energy Regulatory Commission's (FERC) general licensing procedures.

B. Relicensing and Related Revenue Requirement

Q. Which hydro projects has PGE recently relicensed or is PGE in the process of relicensing?

A. On June 21, 2005, PGE and the Confederated Tribes of the Warm Springs Reservation of Oregon (Tribes) jointly received a new 50-year FERC license for the Pelton Round Butte Project, which consists of three developments located on the Deschutes River. PGE has majority ownership shares in two of these developments, Pelton and Round Butte. The third facility, the re-regulation dam (and associated powerhouse), is completely owned and operated by the Tribes. On December 8, 2005, PGE received a new 30-year FERC license for the Willamette Falls Project, which includes our Sullivan facility, located on the Willamette River. PGE is currently in the process of obtaining a new long-term license for the Clackamas River Hydroelectric Project, which is also under FERC jurisdiction. This Project consists of four developments – Oak Grove, North Fork, Faraday, and River Mill – all owned by PGE.

Q. Overall, what relicensing costs has PGE incurred and does PGE expect to incur in the future?

A. These costs fall into three primary categories: capital additions, relicensing process costs, and O&M. First, we expect to invest approximately $301 million for fish ladders, a water intake structure, and other capital additions. Second, we will capitalize approximately $70 million in relicensing process and studies costs. Third, protection, mitigation, and enhancement (PME) measures required by the licenses will increase O&M costs for the projects. The new licenses and related settlements require several measures. For Pelton Round Butte, these include road maintenance and improvements to recreation sites. For

Willamette Falls, PME measures include the responsibility for fish ladder maintenance. Our Clackamas Project will likely require similar PME measures. We project total relicensing-related O&M costs to be approximately $3 million in 2007 increasing to approximately $7 million in 2009, then decreasing to approximately $3 million in 2015, and generally increasing at 2.5% per year thereafter.

Q. Have you prepared a summary table of costs – both actually incurred and projected – by year and by project?

A. Yes. PGE Exhibit 303 provides this information. Pages 1 and 2 of that Exhibit cover capital and O&M costs respectively.

Q. How do these costs affect the test year revenue requirement?

A. The test year net rate base includes approximately $41.7 million related to relicensing. Given the pre-tax cost of capital of slightly less than 13%, the return requirement is approximately $5.4 million. The test year revenue requirement also includes relicensing-related depreciation and O&M expenses of approximately $1.0 million and $2.9 million respectively, resulting in a total hydro relicensing-related revenue requirement of approximately $9.3 million.

Q. Has PGE decided not to relicense any of its hydro projects?

A. Yes. We decided not to seek a new long-term license for Bull Run, our 22 MW hydro facility located on the Bull Run River, just upstream from its confluence with the Sandy River. We determined that the costs associated with measures necessary to obtain a new long-term license would likely exceed the value of the associated power output.

Q. Have you calculated "per MWh" costs for power to be produced by the relicensed plants?

A. Yes. Our calculations reflect the amounts and timing of all costs – both relicensing and other – related to running the hydro facilities covered by the Pelton Round Butte, Clackamas River, and Willamette Falls Projects through the end of the new license terms. We know that the new Pelton Round Butte and Willamette Falls licenses end in 2055 and 2035 respectively. We assume that the new Clackamas River license will run through 2052.

Using "average water," as explained in PGE Exhibit 400, and on a real levelized 2006 dollar basis, these costs are:

- Pelton $21.83/MWh
- Round Butte $22.66
- Clackamas Project $41.90
- Sullivan $45.26

These are substantially lower than comparable levelized market prices of more than $53/MWh.

Q. What net present values result from your calculations?

A. We expect relicensing to provide customers with the following net present value benefits ($2006 Million):

- Pelton $165
- Round Butte $375
- Clackamas Project $143
- Sullivan $ 14
- Total $697

Q. How does the cost of relicensing hydro resources compare to the cost of other resource alternatives?

A. It compares very favorably. The average cost of the resources that are part of PGE's most recent Commission-acknowledged Final Action Plan is more than $40/MWh, even assuming the gas forward curves used to evaluate the RFP bids and the Port Westward alternative. This average would be substantially greater using current forward curves. We base the net present value calculations on an expected long-term 2006 real levelized market power price of more than $53/MWh.

C. Hydro Relicensing Process

Q. Please describe the new long-term licenses that PGE has obtained or is pursuing.

A. FERC issues licenses for hydro facilities with terms ranging from 30 to 50 years.

Our two Deschutes River developments, Pelton and Round Butte, operated under one long-term license for the Pelton Round Butte Project, which expired at the end of 2001. After expiration of the long-term license, the project operated under "annual licenses." On June 21, 2005, FERC issued a new long-term (50-year) license.

For FERC licensing purposes, PGE's Sullivan facility was designated as the Willamette Falls Project. This project, whose long-term license expired on December 31, 2004, was operating under an "annual license" until December 8, 2005, when FERC issued a new long term (30-year) license.

With respect to the Clackamas River, we plan to renew the long-term license for our Oak Grove, North Fork, Faraday, and River Mill developments. These facilities were originally covered by two licenses, one for the Oak Grove Project, the other for the North Fork Project which includes our North Fork, Faraday, and River Mill plants. The two licenses were recently combined and designated as the Clackamas River Project. The current license expires on August 31, 2006, and we have requested a 45-year license. It is impossible to predict when FERC will act on our pending Clackamas application.

Q. What is the relicensing process like in general?

A. The FERC relicensing process is complex and time consuming (usually a minimum of five years). In making relicensing decisions, FERC must consider fish and wildlife, recreational, land use, cultural, and aesthetics issues equally with energy production. Certain federal and state resource agencies, known as "mandatory conditioning agencies," have specific authority to include requirements in FERC issued licenses. These requirements are often expensive, and can limit hydro plants' operational flexibility. Examples are mandatory measures for fish passage and minimum in-stream flows. Often there is insufficient scientific knowledge to objectively determine the environmental effectiveness of some proposed mandatory conditions. Moreover, the FERC relicensing process can become extremely contentious and political. Given this environment, PGE used a collaborative approach to reduce costs and uncertainties wherever possible.

Q. Please describe the relicensing process for the Pelton Round Butte Project.

A. PGE began the relicensing process for the Pelton Round Butte Project in 1995. Following several years of relicensing discussion, PGE and the Tribes filed their Final Joint Application Amendment in June 2001. On August 11, 2002, FERC issued the Ready for Environmental Analysis Notice. This is essentially a determination that FERC has sufficient information to analyze the environmental impacts of relicensing the project. To resolve remaining issues, PGE and the Tribes began a multiparty, facilitated negotiation process in January 2003. Negotiations concerning fish passage, minimum flows below the plants, and associated operational issues, were complex and time consuming. In addition, discussions of the plants' water rights related to future municipal and other water use demands involved many parties. Reaching consensus required a lot of time.

On August 29, 2003, FERC issued its Draft Environmental Impact Statement. In December 2003, PGE and the Tribes filed a description of the Proposed Preferred Alternative with FERC. FERC issued its Final Environmental Impact Statement in June 2004. Parties signed the Settlement Agreement on July 13, 2004, and PGE filed the agreement with FERC on July 30, 2004. FERC issued a new long term license for the project on June 21, 2005.

Q. What were the advantages of PGE's decision to use a multi-party, facilitated negotiation process to relicense the Pelton Round Butte Project?

A. Thirteen agencies claimed some form of mandatory conditioning authority in the relicensing of the Pelton Round Butte Project. A collaborative settlement process provided the best opportunity to reconcile potentially inconsistent demands from these agencies and to maintain the economic benefits of the project for customers. The negotiated settlement involving all parties also greatly reduced the risk of litigation. Litigation over licenses increases costs to customers and raises uncertainty. Moreover, PGE believes that facilitated settlement processes involving all parties create the best opportunity for creative problem solving. We also expect the negotiated settlement to reduce controversy during the implementation of license terms, resulting in more efficient and lower cost implementation of programs.

Q. What must PGE do to meet the conditions of the Settlement Agreement that was part of the Pelton Round Butte Project relicensing process?

A. The Settlement Agreement and the new license, which largely adopts the terms of the agreement, have numerous requirements. The license terms address both project operations and measures to address all resource categories impacted by the project. These categories include wildlife and botanical resources, fisheries, water quality, recreation, culture, road maintenance, and other land uses.

Of particular significance, the new license contains an aggressive fish passage plan, which aims to reintroduce salmon and steelhead above the Round Butte Dam through construction of a new intake tower at the dam.

Q. How will the new intake tower at Round Butte work?

A. The new intake tower, also designated as the Selective Water Withdrawal Tower (Tower), will have two functions. First, by allowing water to be withdrawn from the Round Butte reservoir at a variety of depths, the Tower will create more distinct currents through the reservoir. These currents will guide downstream migrating juvenile salmonids to new fish collection facilities. Second, the Tower will improve water quality, both in the project reservoirs and downstream of the project.

Q. Will the changes made to meet the conditions of the Settlement Agreement alter the output and availability characteristics of Pelton and Round Butte?

A. No. Although the project will operate under a clearer and somewhat more restrictive set of target flows and reservoir levels, the key components of project operations, average energy, and peaking capability, remain intact.

Q. Will the changes made to meet the conditions of the Settlement Agreement change the O&M costs of Pelton and Round Butte?

A. Yes. Many of the requirements of the Settlement Agreement will increase O&M costs. In particular, PGE will pay various entities for road maintenance and law enforcement costs. Also, we will increase the biological staff dedicated to the project and to license implementation. Finally, annual charges paid to the State of Oregon and FERC will increase. Pelton and Round Butte PME-related O&M costs are approximately $2.3 million for the 2007 test year.

Q. Are all hydro relicensing costs directly related to license articles?

A. No. Although it is in all parties' interest to agree on the PME measures that FERC will enforce, there are instances in which the relatively narrow nature of FERC's jurisdiction over licensees does not cover all measures requested by the different parties. In these instances, PGE's negotiating team calculates the cost of these measures and compares those costs to the costs that PGE could incur if we did not achieve settlement.

Q. What are the primary settlement-related costs for Pelton Round Butte that do not directly relate to license articles?

A. In its order issuing a new license for Pelton Round Butte, FERC omitted two elements to which the settling parties had agreed:

1. Support for improvements of Forest Service facilities at Haystack Reservoir. This portion of the agreement requires PGE to pay $10,000 to the Forest Service in the fifth year of the new license. Additional payments of $15,000 each follow in years 20 and 40 of the new license.
2. Improvements to recreation sites on the lower Deschutes. This group of measures requires PGE to support a variety of upgrades to heavily used camp sites along the

Deschutes River below the project. The agreed upon level of support is $87,000 in the fifth year of the license and an additional $49,500 in the seventh year.

Q. What risks did PGE avoid by reaching settlement with all parties?

A. Had we not reached an agreement with all parties, federal and state agencies would have been free, within the limits of their statutory authorities, to mandate mitigation measures that FERC would have been obliged to include in the license. At that point, PGE's only practical recourse would have been to appeal issuance of the license to the federal Court of Appeals. It was PGE's judgment that the outcome of such litigation would have been a license which was, on its face, more expensive for customers than the settlement alternative, and could have involved significant litigation costs as well.

Q. Please describe the process PGE used to relicense the Willamette Falls Project.

A. In relicensing the Willamette Falls Project, we used a variant of FERC's Alternative Licensing Process, under which PGE prepares the environmental assessment on FERC's behalf. Participants in the relicensing process worked in a collaborative fashion, tackling issues incrementally in small technical work groups. This process was successful and resulted in the filing of a Settlement Agreement with FERC in January 2004. All parties have signed this agreement.

The most prominent issue at Willamette Falls was downstream passage of salmonids. Concerns also arose about safe passage of lamprey, a species of cultural significance to the Grand Ronde, Siletz, and Warm Springs Tribes. Petitions were submitted for listing lamprey under the Endangered Species Act. There were also issues regarding traditional tribal uses in the area of the falls. Finally, some parties requested increased public access to the falls through the project and adjacent paper mills. PGE could not meet these requests because of project and paper mill safety concerns and FERC's recent increased emphasis on project security.

PGE filed the Final License Application in December 2002. FERC issued its Draft Environmental Assessment in January 2004, the same month in which PGE filed the Settlement Agreement with FERC. FERC issued its Final Environmental Assessment in October 2004 and a new 30-year license in December 2005.

Q. What must PGE do to meet the conditions of the Willamette Falls relicensing-related Settlement Agreement?

A. PGE must operate the project in accordance with a more restrictive set of license articles. In addition, PGE will upgrade the turbines at Sullivan to improve the units' operating efficiencies and to make them more "fish-friendly." The Settlement Agreement also requires the decommissioning of a small powerhouse previously owned by Blue Heron Paper Company. Finally, the Agreement requires a phased program of improvements to the fish passage facilities at Sullivan and at Willamette Falls themselves.

Q. Will the changes made to meet the conditions of the Settlement Agreement alter Sullivan's output and availability characteristics?

A. No. The Settlement Agreement conditions will leave availability characteristics virtually unchanged.

Q. Will the changes made to meet the conditions of the Settlement Agreement change Sullivan's O&M costs?

A. Yes. The O&M costs at Sullivan will increase, largely for PGE responsibility for maintenance of the Oregon Department of Fish and Wildlife fish ladder located at the site. Sullivan PME-related O&M costs are approximately $200,000 for the 2007 test year.

Q. What process has PGE used to relicense the Clackamas River Hydroelectric Project?

A. For the Clackamas River Project we are using a variant of FERC's Alternative Licensing Process. Under this process, FERC's National Environmental Policy Act (NEPA) contractor, the firm that will eventually write the Environmental Impact Statement for FERC, participates in the process from the beginning, working with the applicant and relevant agencies. Relicensing participants work in a collaborative fashion, tackling issues incrementally in small technical work groups.

Much of the Oak Grove portion of the project is on Forest Service lands, which gives the Forest Service broad authority to mandate license conditions. Flow below the Harriet Lake diversion dam is a significant issue. Proximity to the Portland metropolitan area makes recreational use of the Clackamas Basin a major factor. Finally, most portions of the project have some form of up- and down-stream fish passage. The efficiency and appropriateness of the fish passage system is a major concern.

Relicensing participants completed scoping, the first phase of the collaborative process, and PGE issued a revised Scoping Document in April 2003. Concurrent with relicensing, PGE asked for a license amendment as part of its Endangered Species Act (ESA) compliance strategy. In June 2003, FERC granted this amendment, which included several fishery conservation measures and authorized new turbine runners at North Fork and Faraday #6. PGE issued the initial draft of its Preliminary Draft Environmental Impact Statement at the end of September 2003 and filed its Final License Application and associated Preliminary Draft Environmental Impact Statement in August 2004. With the completion of the Final License Application, PGE convened a settlement group, whose goal was to resolve the licensing issues via a collaborative settlement.

Q. Was the settlement group successful?

A. Yes. The group reached consensus on the outstanding issues. This resulted in an Agreement in Principle, which was filed with FERC on June 30, 2005.

Q. What must PGE do to meet the conditions of the Agreement in Principle?

A. As with the Pelton Round Butte Project, the Agreement for relicensing the Clackamas River Project contains significant measures to improve the survival of salmon and steelhead passing through the project. Of greatest significance, the agreement contains minimum flows in the Oak Grove Fork of the Clackamas River below Harriet Dam and requires new fish passage facilities to be constructed at PGE's North Fork and River Mill facilities. The agreement also contains measures to improve recreation in the project area, and to protect wildlife habitat and species, cultural and historical resources, and water quality.

Q. Will the changes made to meet the conditions of the Agreement in Principle alter the output and availability characteristics of PGE's Clackamas River hydro facilities?

A. The availability characteristics of the four facilities included in the Clackamas River Hydroelectric Project will remain largely unchanged. The combined energy output of these three plants will fall by approximately seven MWa because of increased minimum flow requirements at Oak Grove and Faraday, and head loss at North Fork.

Q. Will the changes made to meet the conditions of the Agreement in Principle change the O&M costs of PGE's Clackamas River facilities?

A. Yes. Staffing requirements to fulfill license obligations, increased operational requirements for campgrounds, and payments for road maintenance and law enforcement will increase O&M. Clackamas PME-related O&M costs are approximately $400,000 for the 2007 test year.

Q. Why did PGE decide to use a collaborative variant of FERC's Alternative Licensing Process for its Clackamas River and Willamette Falls Projects?

A. This choice provided the best chance of creating firm information bases and preliminary agreements, which could then serve as the foundations for comprehensive settlements. The collaborative process resulted in negotiated settlements, which will likely reduce both the controversy during license term implementation and the possibility of litigation. This reduction of conflict is likely to reduce costs and uncertainties for customers.

Table of Contents

I. Introduction

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

A. My name is Stephen Hawke. I am Senior Vice President of Customer Service and Delivery. My name is Bill Nicholson. I am Vice President of Distribution. 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 explain PGE's 2011 test year Transmission and Distribution O&M expenditures, and how they support PGE's goal of adding customer value through operational excellence and improvement.

Q. Please summarize PGE's Transmission and Distribution O&M costs and capital expenditures from 2008 through the 2011 test year forecast.

A. Table 1 below summarizes this information:

Table 1
Summary T&D Changes ($ Million)

	2008 Actuals	2011 Test Year
Transmission O&M Expenses	$10.8	$12.6
Transmission Capital Expenditures	$39.7	$8.1
Distribution O&M Expenses[1]	$69.3	$84.1
Distribution Capital Expenditures[2]	$127.1	$140.6

The amounts, reflected in Table 1 as capital expenditures, represent capital expenditures for the year. The amount of an expenditure that closes-to-plant in a specific year is presented in PGE Exhibit 300.

Q. Please explain why PGE's Distribution O&M increases significantly from 2008 to 2011, by approximately $14.8 million.

[1] Actual costs for the Performance Management Group are normalized to reflect shift from Distribution to A&G with no change to PGE's corporate costs.
[2] Exhibit 300 (Revenue Requirement), Table 7 lists only core Distribution activities in the Distribution amounts for 2008 ($117.4 million) and 2011 ($138.8 million). Table 1 above, includes approximately $9.7 million in 2008 and approximately $1.8 million in 2011 that are activities included in the "Strategic" amount in Table 7.

A. PGE's Distribution O&M increase, between 2008 and 2011, is due to two major factors: 1) higher costs to restore service lines, in part due to the replacement of our insurance coverage for major storms; and 2) higher information technology (IT) costs. These two items are responsible for approximately $12.5 million of the increase. We discuss these and other increases in the Distribution section later in our testimony.

Q. How is the remainder of your testimony organized?

A. After this introduction, we discuss Transmission non-labor O&M and planned capital work in Transmission. In Section III, we discuss Distribution, beginning with goals and enhancements made to our technological systems. In this section we also provide an overview of cost increases in Distribution O&M; we discuss increases in our restoration expenses, Distribution IT, Tree Trimming, FITNES, and Locating programs, and the increasing costs in these programs. Our last section contains our qualifications.

II. Transmission

A. Transmission O&M Expenses

Q. Do transmission Full Time Equivalents (FTEs) increase from 2008 to 2011?

A. No. FTEs remain at approximately 27 from 2008 to 2011.

Q. Please identify the changes in non-labor O&M costs from 2008 to the 2011 test year forecast that are associated with Transmission.

A. Transmission non-labor O&M expenses increase by approximately $1.0 million, from around $5.4 million in 2008 to approximately $6.5 million in 2011.

Q. What accounts for the $1 million increase in non-labor Transmission O&M expenses?

A. There are two major drivers of the increased cost: 1) fees and use-of-facility charges, which are expected to increase by approximately $0.5 million, and 2) the first-year cost of the intertie insulator replacement program for the 500 kV lines, equal to approximately $0.5 million.

Q. Please discuss the increases in fees and use-of-facility charges

A. Fees and use-of-facility charges are expected to increase by approximately $0.5 million from 2008 to 2011 for three reasons:

- An increase in the Captain Jack Substation and AC Intertie use-of-facility charges - $0.2 million. The BPA use-of-facilitiy (UFT) charges for the Captain Jack Substation and the AC Intertie are increasing due to revised BPA assessments of the investment values of these facilities.
- Increased payments to Open Access Technology International (OATI) - $0.13 million. OATI's monthly fees are increasing with the addition of web accounting and dynamic scheduling capabilities to PGE's transmission management software. OATI supplies

PGE with an updated FERC/North American Energy Standards Board-compliant Open Access Same-Time Information System (OASIS) and transmission management software.

- Increased fees paid to BPA for substation work - $0.17 million. BPA is increasing the fees that PGE must pay for substation work at BPA's Grizzly, Malin, and Pearl substations.

Q. What does the $0.5 million expense for intertie insulators represent?

A. This is the first-year cost of a five-year program to replace insulators in our transmission system that are approximately 40 years old.

Q. Why is PGE initiating a program to replace intertie insulators on its 500 kV lines?

A. PGE has tested a sampling of the insulators on several of its 500 kV lines and found evidence of age-related insulator deterioration in a significant number of those sampled. During an extreme loading event, a portion of the insulators could become loaded beyond their current (reduced) capacity, which would result in significant outages. PGE has decided that a phased replacement program is warranted to maintain adequate reliability on the transmission system. The program will replace insulators on the Grizzly-Malin 500 kV line and Grizzly-Round Butte 500 kV line.

B. Transmission Capital

Q. What transmission-related capital work is PGE planning that affects the 2011 test year?

A. PGE is planning three major capital transmission projects: (1) the Transmission and Distribution Capacity Expansion Project, (2) the Oregon California Intertie Project, and (3) the Cascade Crossing Transmission Project. None of the expenditures for the Cascade

Crossing Transmission Project close to plant in the test year. Table 2, below, summarizes the capital expenditures for these projects for 2009 through 2011:

Table 2
Transmission Capital Expenditures ($ Million)[3]

	2009 Forecast	2010 Budget	2011 Test Year
Capacity Expansion Project	$9.0	$3.6	$3.9
Oregon California Intertie Project	$3.3	$7.3	$1.4
Cascade Crossing Transmission Project	$2.8	$5.4	$2.8

Q. Please explain the Capacity Expansion Project?

A. PGE's Transmission and Distribution Capacity Expansion Project is a multi-year project to address system needs by expanding and upgrading PGE's transmission system. This project is being implemented to comply with North American Electric Reliability Corporation (NERC) regulations and to provide capacity for continuing area load growth. PGE made major land purchases and completed the majority of the Willamette Valley Conversion in 2009. By 2011, PGE will complete the conversion of the Middle Grove substation to 115 kV in the Salem area. PGE will continue to incur expenditures associated with construction of 230 kV transmission for the new Horizon substation in Hillsboro as we make progress toward a 2014 completion date.

Q. Capital expenditures for the California Oregon Intertie (COI) project total approximately $12 million for the period 2009 through 2011. What will this project accomplish?

A. The COI project is a multi-year project to upgrade its capacity. The expenditures from 2009 through 2011 correspond to the agreed upon contractual payment schedule with BPA. The COI is currently rated at 4,800 megawatts, but it frequently operates at less than full capacity due to various operating constraints. When power flows exceed the COI's operational

[3] The capital amounts in the table represent capital expenditures for the year. The amounts that represent plant in rate base are presented in PGE Exhibit 300.

transfer capability, which is the industry threshold for safe and reliable operation, transmission transactions must be curtailed to reduce power flows to acceptable levels. The COI project will install new high-voltage equipment at several critical bottlenecks in the system. This equipment will reinforce the intertie so it can operate at full capacity more frequently, and under a wider range of conditions.

Q. Why is PGE considering the Cascade Crossing Transmission Project?

A. The Cascade Crossing Transmission Project will provide an East-West connection to existing and planned thermal resources and to existing or potential renewable resources east of the Cascades. In addition to this increased access, benefits include improved grid reliability and transmission needed to meet PGE's IRP energy goals.

Q. For 2009, 2010, and 2011, capital expenditures for the Cascade Crossing Transmission Project total approximately $11 million. What are these costs for?

A. The majority of the costs are for environmental assessments, permitting, licenses, and fees. The remainder is for public outreach and initial efforts to secure options on key properties. As indicated above, none of these costs closes to plant in the test year.

III. Distribution

A. Distribution Overview

Q. How does the OPUC measure/evaluate service quality at the Distribution level?

A. PGE submits annual service quality measure (SQM) reports, which contain outage and other results. The Commission Staff audits our SQM reports and enforces defined performance levels. Two of PGE's service goals–less than 1.0 outage, and less than 3.0 momentary outages–are the most stringent for investor-owned utilities in Oregon, and PGE consistently meets the OPUC weighted-average goals for those two measures. The target outage frequency goal (outages lasting 5 minutes or more) is no more than one per customer per year. The actual results have been less than one outage per customer, per year for the last four years. The target goal for momentary outages (less than 5 minutes) is no more than three momentary outages per customer per year. The actual results have been well below that for the last four years. PGE also annually reports the results of its System Average Interruption Index (SAIDI).

Q. What is SAIDI?

A. SAIDI is the total time during a year the average customer is without power, measured in minutes. It is an indicator of system reliability. All planned and unplanned interruptions of five minutes or more are included in the calculation. Major events are excluded. PGE's goal is fewer than 90 minutes.

Q. How are major events defined by the OPUC?

A. The OPUC definition of a "major event" means a catastrophic event that a) exceeds the design limits of the electric power system; b) causes extensive damage to the electric power system; and c) results in a simultaneous sustained interruption to more than 10 percent of the metering points in an operating area.

Q. What are PGE's SAIDI results for the last four years?

A. In 2007 and 2008, PGE met its service quality goal of less than 90 minutes. However, in 2006 and 2009, PGE exceeded the 90 minute goal due to circumstances outside of its control.

Q. What events affected PGE's SAIDI outcomes in 2006 and 2009?

A. PGE had a number of storms in those two years that under the OPUC definition of major events could not be excluded from our results, since they did not result in a simultaneous sustained interruption to more than 10 percent of our customers. However, these storms were large enough to affect our SAIDI results.

Q. Is PGE recommending the adoption of a new service quality standard?

A. Yes. We recommend adoption of the Institute of Electrical and Electronics Engineers (IEEE) Standard 1366-2003 reliability reporting standard for SAIDI.

Q. How does the IEEE 1366 reliability standard distinguish between outages that occur on "normal" days and major outages?

A. The standard sets a threshold value for daily system SAIDI. On any day, if the accrued SAIDI minutes exceed the threshold, that day is considered a major event day (MED) and is analyzed separately from events occurring on days that are not MEDs.

Q. Why does PGE want to adopt this reliability standard?

A. PGE faces two challenges: providing reliable service on an "every day" basis and responding to major events that threaten overall system integrity. The 1366 Standard does a better job than the current standard in assessing how well we perform in these two areas.

Q. What are other advantages of adopting this standard?

A. Other advantages include:

- Uniform reporting among utilities. Over 40 utilities across the country have adopted the new IEEE standard, and PacifiCorp calculates and reports SAIDI using 1366 in all States it serves <u>other</u> than Oregon.
- Use of an objective measure with a sound theoretical basis developed by a consortium of utilities, commissions, consultants, and academics.

Q. What other OPUC requirements are included in the SQM reports?

A. The other program results included in the SQM reports are as follows:

- Substation Safety & Equipment Condition Assessment (monthly inspection of all substations).
- Overhead switch maintenance program (all overhead line switches are inspected, maintained, repaired as necessary and operated on a 5 year cycle).
- Underground switch maintenance program (same as above but for our pad mounted switches of the underground areas of our distribution system).
- Recloser maintenance program (pole top reclosers are rotated for servicing at our shops in a 5-year cycle).
- Pole top regulator program (also removed from service as they are rotated to the shops for servicing in approximately a 5-year cycle).
- Marina inspection program (all marinas with PGE electrical facilities on the docks, primarily house boat moorages, are inspected twice a year; during high water and low water, looking for National Electric Safety Code (NESC) issues.
- Safety survey (drive by inspection program for the overhead system looking for items needing attention such as unreported storm damage, accomplished in a 2-year cycle).

- 10 underperforming feeder program (the 10 poorest performing feeders are analyzed yearly for reliability improvements to reduce outages, and work is then budgeted and completed).

Program results that are not required SQMs but are voluntarily reported include:

- Transmission full pole testing (climbing inspection to determine if decay is present in wood transmission poles put in service prior to 1980) and replacement program.
- New pole quality assurance inspection (a random sample of new poles to perform a quality assurance inspection for NESC compliance, design compliance, and PGE standards compliance (1440 poles inspected in 2009).
- Pad-mounted switch gear infrared inspection (pad mounted distribution switches are inspected for infrared hot spots on a yearly basis).

These programs are in addition to annual programs such as Tree Trimming, Locating, and FITNES that we perform annually in the Distribution area.

B. Distribution O&M Expenses

Q. Please identify the changes in Distribution O&M costs and FTEs from 2008 to 2011.

A. Distribution O&M expenses increase from approximately $69.3 million to $84.1 million, an increase of approximately $14.8 million while FTEs increase by approximately 5.

Q. If labor is not a major driver of cost increases, what are the non-labor factors that increase Distribution O&M expenses?

A. As Table 3 below shows, there are three major drivers of increased non-labor O&M expenses in Distribution: 1) approximately $7 million for restoration of service lines, 2) approximately $5.3 million for Distribution IT, and 3) approximately $1.7 million for tree trimming costs. Other minor drivers are FITNES (approximately $400,000), and locating costs (approximately $300,000).

Table 3
Distribution Non-Labor O&M Drivers of Cost Changes
from 2008 to 2011 Test Year Forecast

Cost Driver	**$ Million**
Restore Service Lines	7.0
Distribution IT	5.3
Tree Trimming	1.7
FITNES Program	0.4
Locating Cost Increases	0.3
Total of Non-Labor Cost Drivers from 2008 to 2011	**$14.7**

We explain each of these drivers in more detail below.

1. Restore Service Lines

Q. Costs to restore service lines increase by approximately $7 million from 2008 to 2011. What is the primary reason for this increase?

A. The primary reason for the increase, approximately $4.5 million, is due to the proposal for a balancing account that would replace PGE's expiring property insurance coverage for the transmission and distribution (poles and wires) system.

Q. Doesn't PGE currently have property insurance that covers its poles and wires?

A. Yes, but we were unable to acquire replacement insurance coverage with similar terms and conditions for our T&D system. PGE Exhibit 1000 discusses the expiring T&D insurance coverage in more detail.

Q. Please describe the proposed balancing account.

A. PGE is proposing a balancing account to track the differences between what we characterize as a "Level III outage" actual costs and amounts collected in rates. The balancing account would earn interest at PGE's authorized cost of capital and would be subject to prudence review and/or audit.

Q. What is a Level III outage?

A. Level III is our most severe customer outage level. As noted in Table 4 below, PGE classifies outages into three levels, from least to most impact on our system. A Level III outage means that we, in general, expect an impact of at least 50,000 customers, or across three to four of our regions, or several substations and feeders will be out of service.

Table 4
PGE Classifications for Outages

Level I - refers to typical daily occurrences on the distribution system. These outages will increase phone calls from customers, but should not cause a hardship on call center staff. The following activities are considered Level 1 incidents:	·Two feeders out in service territory.
	·Two thousand customers or less out of service at multiple locations.
	·Restoration can be completed in less than 24 hours.
Level II – this level increases substantially the number of calls due to outages. Typically, two or less regions are involved and restoration can be completed with PGE resources. The following activities are considered Level II incidents:	·Four or more feeders or multiple tap lines out of service.
	·20 to 30 thousand customers out of service at multiple locations.
	·Restoration can be completed in 48 hours.
	·Incident may generate media attention.
Level III – at this level, many customers will be out of service. Call center will generally require support from other areas of the company to support customer calls. Management will contact other utilities for possible assistance in restoration efforts. The following activities are considered Level III incidents:	·Multiple substations and feeders out of service.
	·Greater than 50,000 customers out of service.
	·Three or four regions are experiencing outages.
	·Greater than 72 hours to restore service.
	·Outside assistance may be required.

Q. How often would the account balance be reviewed?

A. The account would be reviewed at least every two years, at which time changes could be proposed.

Q. Is there a proposed cap on the balancing account?

A. Yes. As we noted, PGE proposes to collect $4.5 million annually. We determined this amount by reviewing actual storm history and the pattern of losses over the last 15 years. Of the $4.5 million, $3.5 million would be subject to accrual in the balancing account while the remaining $1 million would be recovered in fixed O&M.

Over two years, the amount collected in the balancing account, if there were no major Level III outage events, would be $7 million. This would effectively be a cap. Also, after the second year, the balancing account would be reviewed and the cap may reset.

Q. What costs would be included in the proposed balancing account?

A. Only a Level III outage event involving our T&D system, which receives a PGE accounting job number, would be included. However, only expenses above $1 million for each Level III outage event would be placed in the balancing account.

Q. When does PGE assign a job number to a Level III outage event?

A. We assign a job number when circumstances are expected to cause a Level III outage event that impacts our T&D system.

Q. Please give an example of how the balancing account would work over a 7-year period.

A. See Table 5 below, which shows in Year 1 (2011), PGE collecting $3.5 million in the balancing account each year and experiencing multiple Level III outage events over the following 6 year period.

Table 5
Balancing Account Example

	Level III outage event Costs	Exclusion	Net Costs	Annual Collection	Balancing Account
Year 1	6.0	(1.0)	5.0	(3.5)	1.5
Year 2	2.0	(1.0)	1.0	(3.5)	(1.0)
Year 3	0.5	N/A	0.0	(3.5)	(4.5)
Year 4	0.0	N/A	0.0	(3.5)	(8.0)
Year 5	12.0	(1.0)	11.0	(3.5)	(0.5)
Year 6	5.0	(1.0)	4.0	(3.5)	0.0
Year 6 (2nd storm)	2.5	(1.0)	1.5	(3.5)	(2.0)
Year 7	1.0	N/A	0.0	(3.5)	(5.5)

For purposes of this example, interest is excluded from the calculation. In addition, the example shows one Level III outage event per year. If PGE experienced multiple Level III outage events per year that impacted our T&D system, the $1.0 million exclusion would be applied on a per-Level III outage event basis.

Q. Are there alternatives other than a regulatory mechanism?

A. Yes, possibly. PGE is open to discussions with Staff and other parties on the specific characteristics of alternative mechanisms that allow for a smooth recovery on Level III outage events that impact our T&D system.

Q. What accounts for the remaining increase of $2.5 million in non-labor costs?

A. Approximately $1.7 million of the increase is due to the effect of a 2008 credit from the insurance proceeds for the large 2008/2009 winter storm. Although there were storm costs of approximately $500,000 in 2009, the entire insurance proceeds were booked to 2008. Also, the proceeds apply to all restoration costs (i.e., labor and non-labor), PGE applied the entire amount to non-labor accounts. After normalizing for the 2008 storm, non-labor restoration costs increase by approximately $800,000 from 2008 to 2011 due to higher vehicle allocations.

2. Distribution Technology Enhancements and Distribution IT

Q. What technology enhancements has PGE completed?

A. The following technology enhancements were performed to better assist our customers during outages and to more quickly resolve safety issues such as downed wires:

- The Online Outage website: Released on PortlandGeneral.com in July 2009, this website provides customer and news media access to general information about current outages within PGE's service territory. There are two main components to these new web pages: an outage map and an outage list. The outage map aggregates outage information by zip code to give an overall status of outages in a particular area. Zip codes with more than 5 customers out of power will display a pushpin, which customers can click on to view more information. Weather information is also available on the outage map page to show how weather could be impacting the current outage status. The outage list page is aggregated by county and by zip code. Clicking on a particular county on the main list page allows the user to view a list of outages in that county sorted by zip code. Information provided on the outage list page is comparable to information provided over the Interactive Voice Response (IVR) phone system today. These web pages were developed internally by Distribution Application Services.
- The Color Coded Wire Incident Application: Displays wire down outages from Outage Management System (OMS) as pushpins in Google Earth using several layers of kml files[4]. Each pushpin represents a wire incident outage at a particular transformer location. The pushpins are color-coded based on the status of the

[4] A file format used to display geographical data. When data are taken from a database (OMS in this case) they are extracted along with latitude and longitude coordinates and can be mapped in Google Earth or other types of mapping products.

outage (unassigned, assigned, emergency, resolved). Displaying the wire incident outages on Google Earth helps the wire down desk and dispatch office to respond to outages more effectively using geographic dispatching methods and allows them to spot emergency wire situations more quickly. The result is more efficient resolution of wire incident outages in major events, which enhances public safety.

- Meter Pinging: Allows repair dispatchers and line dispatchers to ping AMI meters to determine whether they are energized. The application allows the dispatchers to search for meters by feeder, transformer number, or meter number. Once located, the application allows the user to ping the meter to determine whether we have communication with the meter. If the ping request is returned as a "pass" then the meter is energized. If the ping request is returned as a "fail," then we do not have communication with the meter and further investigation is required to determine if there is an outage. This capability will enable dispatchers to trouble shoot outages more effectively. This is especially true with single customer outages that could be resolved without dispatching a crew, resulting in savings for the company.
- Automated Vehicle Locating (AVL): Implemented AVL with over 100 vehicles (mostly assigned to single-man crews). This capability allows PGE to know where these crews are located and will help us respond to potential safety issues as well as dispatch these crews more efficiently. While access to this application is extremely limited on a day-to-day basis, during storms all dispatchers will have access and will be able to dispatch and utilize these crews more efficiently.

Q. How much are Distribution IT costs increasing from 2008 to 2011?

A. We expect costs for Distribution IT to increase by approximately $5.3 million from 2008 to 2011.

Q. What are the primary reasons these costs are forecasted to increase?

A. The primary area of increase is allocated IT charges. These IT allocations consist of costs for information systems needed to support our operations; system replacement costs; increasing cyber security requirements for hardware, software and network systems; growing data storage requirements; and higher overall costs charged by vendors for maintenance agreements on PGE's systems. These costs are discussed in more detail in PGE Exhibit 600.

3. Tree Trimming

Q. How did you estimate tree trimming costs for 2011?

A. The Tree Trimming program consists of two- or three-year cycles and is contracted on a time and material basis. PGE first determines the number of crews necessary to complete the work to meet the Oregon Administrative Rule (OAR) 860-024-0016, and to complete the program descriptions contained in PGE's SQMs, and then applies the labor rates for the crews to determine total costs.

For the work in 2011, we forecast a need for 36 tree trimming bucket crews, 2 sub transmission trimming crews, 3 backlot trimming crews, 2 one-person response crews and 1 cross country right-of-way climbing/clearing crew.

Q. Comparing 2008 to 2011, are the amount of work and the number of contract crews expected to be similar?

A. Yes, we believe that they will be assuming similar weather and temperature conditions.

Q. If the amount of work and contract crews remains the same, why are tree trimming non-labor costs higher by approximately $1.7 million?

A. The increase is due primarily to the rates in the new union contract, which account for approximately $1 million of the increase. In 2009, Asplundh Tree Experts and IBEW Local 125 negotiated a new three-year contract. The negotiations lasted seven months and involved mediation. The outcome was higher wages for union employees. For PGE, which uses Asplundh, the rate for a standard two-person trimming crew increased approximately 3% per year.

The remaining amount of approximately $700,000 is related to an accounting accrual booked in 2008. The accrual, a non-budget item, is part of the year-end accounting process to properly record expense in the year that services were received. The 2008 credit amount of approximately $700,000, which is absent in 2011, indicates that the accrual amount related to December 2007 that reversed in 2008 was more than the accrual for unpaid tree trimming services that was recorded in December 2008, or in other words, we had more unpaid invoices in December of 2007 than we did in December of 2008.

Q. What is PGE doing to keep contractor costs reasonable?

A. PGE bid the tree-trimming contract in 2007, and will bid the contract again in 2010, to ensure we are receiving competitive pricing. We also manage the contract and ensure costs are reasonable and meet required specifications. PGE has a staff of seven foresters and one forester supervisor to perform this management role.

The foresters assign the work by designating trees to be trimmed or removed and they also coordinate with customers when necessary. As trimming progresses, the foresters inspect the trimming for productivity, which is determined by actual versus estimated costs, along with adherence to clearance, arboricultural, and safety specifications.

Efforts to control costs by the foresters include activities such as ensuring the contract crews are located as close to the project as possible, thereby minimizing travel time;

managing trimming debris by blowing chips back on site versus into a dump truck, thereby minimizing non-productive time spent to dump chips; requiring a project work progression plan so the crews do not have to shift job sites frequently; and requiring that the scheduling of extra resources like flagging or equipment is timely and efficient.

4. Facility Inspection and Treatment to the National Electric Safety Code (FITNES)

Q. Please describe PGE's FITNES program.

A. The FITNES program inspects, maintains, and repairs all of PGE's 280,000 poles on a 10-year cycle, and all of our underground equipment on a 4-year cycle, including PGE equipment located on large industrial campuses.

Since PGE launched the program in 1987, annual poles needing to be replaced due to decay have declined from 12% to 0.7%, saving millions of dollars in replacement costs. This is important preventive maintenance that extends equipment life, reduces costs, and increases safety. In addition, FITNES identifies potential public safety issues and resolves them before they cause outages.

Q. Why are costs increasing by approximately $400,000 between 2008 and 2011?

A. In 2008, the underground portion of the FITNES program completed the final year of the last four-year cycle, inspecting 18,200 units that year. In 2009, the current four-year cycle began. In 2011, approximately 22,000 units will be inspected if we are to maintain a four-year cycle. Over time, the number of units to be inspected will increase as residential and commercial developments add new underground facilities to our service area.

Q. Is a four-year cycle the appropriate length of time for underground inspection?

A. No. PGE has inspected its underground facilities on a 4-year cycle since 1996. Since then, we have completed multiple cycles and we believe a four-year cycle is unnecessary given the excellent condition of our underground facilities. A 10-year cycle would be more appropriate and cost effective for our customers. We estimate that moving to a ten-year cycle would save approximately $900,000 in 2011 alone.

Q. Is a ten-year cycle supported by the OARs?

A. Yes. OAR 860-024-0011 (1) (B) (c) states the cycle length for underground facilities inspection as 10 years maximum with a recommended rate of 10% of the system per year.

Q. Do other Oregon utilities currently have a 10-year cycle?

A. Yes. Pacific Power performs underground inspections on a 10-year cycle.

5. Underground Utility Locating ("Locating")

Q. Why are costs increasing by approximately $300,000 for locating?

A. The reasons for the higher costs are due to higher contract costs, and the number of locate requests forecasted in 2011. We explain these factors in more detail below.

a. Locating Contract Costs

Q. Why are contractor costs increasing?

A. PGE's Locating contract was renewed in September 2009. As part of the negotiations, the contractor's rates increased to reflect their increased costs (according to the CPI forecast) for 2010 and 2011. This contract is bid on a unit-price basis and we have tracked the average cost per locate since 1991.

Q. How does PGE's current cost per locate compare to 1991?

A. PGE is paying less per locate today than in 1991; approximately 6% less per locate, unadjusted for inflation. When adjusted for inflation, PGE is paying approximately 41% less per locate than in 1991.

b. Locating Requests ("Locates")

Q. How does PGE forecast the number of locates for the 2011 test year?

A. PGE considers actual numbers of locates for the last three to five years to forecast the anticipated number of locates for 2011. Over the last three years (2006-2008), the average growth in locates was 6.5%. Over the last five years (2004-2008), the average growth was 6.3%. Thus, the growth has been fairly stable. We decided to use a 6% growth rate for 2010 and 2011 to reflect these historical averages.

Q. How much have locates increased from 2008 to 2009 year-to-date?

A. The number of locates is nearly flat when comparing 2008 to 2009. However, 2008 was a high year for locate requests, up 14.2% from 2007.

Q. If 2008 was a high year for locates and locates have not increased in 2009, why is PGE forecasting 6% growth for the 2011 test year?

A. PGE believes that trending the last three to five years of locates gives us the best forecast for the 2011 test year, allowing for the peaks and valleys of requests we actually receive. This method has routinely kept us within budget in the past, but may not accurately forecast growth in locates beyond 2011.

While past activity may be a reasonable indicator of future growth for programs such as Tree Trimming or FITNES (where there is a set amount of work during each cycle and growth in our system can be reasonably forecasted), that is not the case in locating. PGE is required to perform locates upon request and the amount of locating work is dependent upon the amount of requests received. There are other factors that can increase the amount of locates that historical trends cannot accurately reflect.

Q. What other factor might increase the number of locates beyond 2011?

A. Increased public awareness increases the number of locates. PGE is actively involved with local and national committees to effectively educate the public on calling 811 before digging. Local examples of increasing public awareness are: 811 billboards on I-5; training over 800 Oregon contractors on safe digging practices; training over 3,000 Home Depot employees in Oregon stores to remind customers with digging projects to call 811 first; and the airing of Public Service Announcements (PSAs) on both TV and radio.

National examples of increasing public awareness are: partnering with corporate Home Depot to spread the Oregon pilot nationally; the partnership of Williams Pipeline and the Common Ground Alliance (CGA) to create a children's educational video, curriculum and distribution plan to begin to educate the importance of calling 811 before you dig at the elementary school level. All of these examples occurred in 2009, building on the many examples of public awareness over the years. CGA is currently working with a sponsor to display the 811 logo on their NASCAR in three different locations.

Q. What is the purpose of 811?

A. The 811 number is federally mandated to provide a single point of contact to call for digging projects anywhere in the U.S. Nationwide, there are more than 60 one-call numbers (centers that notify the various local utilities or their contractors to mark underground lines). 811 routes calls to the appropriate one call center, similar to 911 calls, eliminating the need to know the various 1-800 numbers.

The consolidated efforts and ease of the Call 811 campaign reaches millions of people through multiple media methods, as noted above, resulting in greater public safety from dig-ins and reduced damages to underground utility infrastructure.

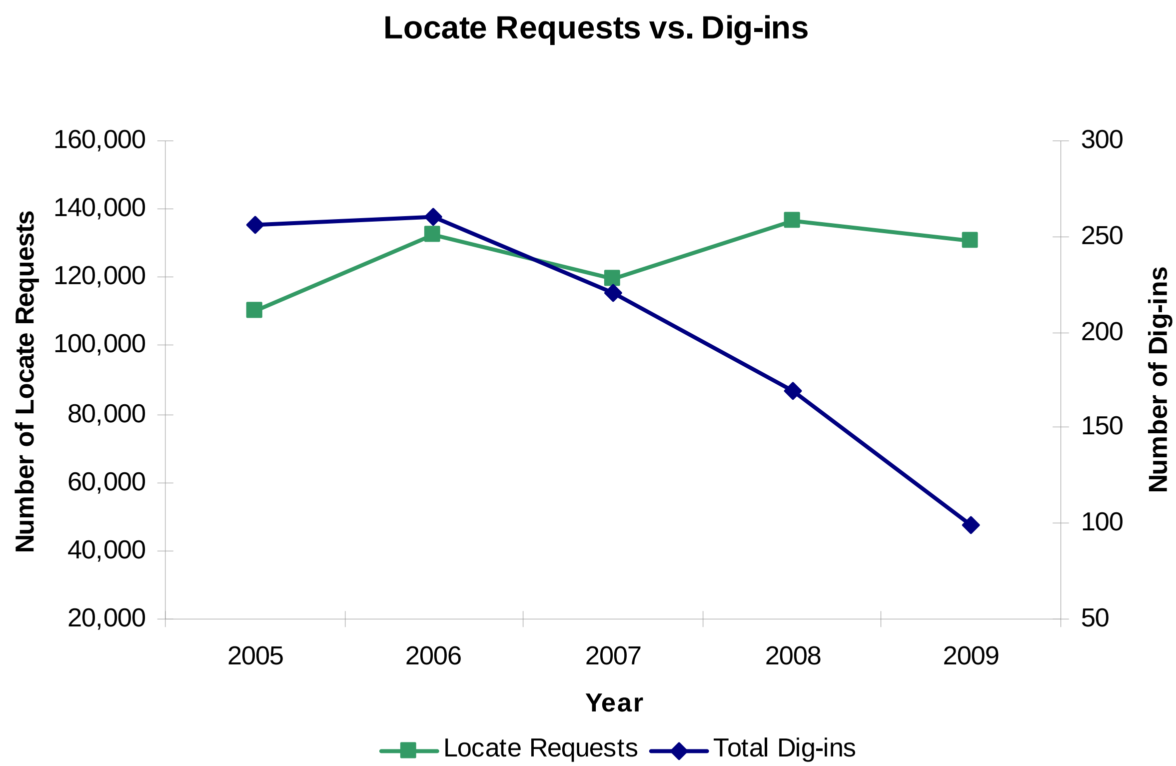
Q. Have underground utility damages decreased since the implementation of 811?

A. Yes. The 811 number went live in May 2007 and as of 2008 the estimated total number of underground utility damages occurring in the U.S. decreased to 200,000 from an estimated 456,000 in 2004, according to the latest CGA Damage Information Reporting Tool.

Q. Has PGE experienced decreased underground utility damages?

A. Yes. PGE damage incidences have decreased from 256 in 2005 to just 99 in 2009. Figure 1 below, shows the significant drop in damages to our system from 2005 to 2009.

Figure 1



The above graph shows the relationship between the number of locate requests received by Portland General Electric and the number of respective dig-in damages that were recorded from 2005 through 2009.

Q. Does PGE's 2011 test year budget reflect the decrease in the number of dig-ins?

A. No. The cost of repair is billed to the person who caused the dig-in, so while decreasing dig-ins is very important from many viewpoints, such as safety and reliability, the decrease does not impact our Distribution O&M expenses.

Q. Does PGE expect the number of locates to increase in 2011?

A. Yes, for two reasons. First, greater public awareness results in more locate requests. A survey conducted by CGA just prior to the 811 Campaign launch in 2007 concluded that only 33% of people with digging projects requiring a utility locate actually called. With educational efforts continuing into the future, we expect to see a continuing increase in the percentage of people calling for locate requests.

Second, the economy is showing a slight recovery and should continue to strengthen through 2010 and 2011. Improved economic conditions will result in more construction activities that result in more locate requests.

IV. Qualifications

Q. Mr. Hawke, please describe your educational background and qualifications.

A. I received a Bachelor of Science Degree in Electrical Engineering and a Bachelor of Science Degree in Mathematics from Oregon State University. I received a Master of Business Administration from Portland State University. I completed additional graduate work at Portland State University in Systems Science and graduated from the Public Utilities Executive course at the University of Idaho. I am a registered professional engineer in the State of Oregon. My employment with PGE started in 1973, as an Assistant Distribution Engineer. I have held positions such as Engineering Supervisor, Chief Underground Engineer, Chief Field Engineer, Sales Manager, Regional Manager in both the Southern and Western regions, Manager of Response and Restoration, General Manager of System Planning and Engineering, and Vice President of System Planning and Engineering. In August 2004, I became Vice President of Customer Service and Delivery. I began my current position of Senior Vice President of Customer Service and Delivery in August of 2006.

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, before assuming my current role as Vice President of Distribution in August of 2009.

Q. Does this conclude your testimony?

A. Yes.

Table of Contents

I. Introduction

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

A. My name is Stephen Hawke. I am Senior Vice President of Customer Service and Delivery. My qualifications appear in PGE Exhibit 800.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present an overview of Customer Service, including our goals and objectives. I also explain PGE's Customer Service expenses for the 2011 test year.

Q. How much do Customer Service O&M costs increase from 2008 to the 2011 test year forecast?

A. Customer Service O&M expenses increase from approximately $68.0 million in 2008[1] to approximately $70.7 million in 2011, approximately $2.7 million.

Q. Do FTEs increase from 2008 to 2011?

A. No. In fact, the number of FTEs should decline.

Q. Is the reduction in FTEs due entirely to the impact of AMI?

A. No. After normalizing for Advanced Metering Infrastructure (AMI), Customer Service FTEs in 2011 are still lower than in 2008.

Q. If labor is not a driver of cost increases, what are the non-labor factors that increase Customer Service O&M costs?

A. There are primarily four factors, as shown in Table 1 below.

[1] Actual costs for the Performance Management Group are normalized to reflect its move from Customer Services to A&G with no change to PGE's corporate costs.

Table 1
Customer Service Non-Labor O&M Cost Changes
from 2008 actuals to 2011 Test Year Forecast

Cost Driver	**($Million)**
Information Technology	4.1
100	1.7
Write-offs of Uncollectible Accounts	
Other Factors	0.4
Meter Reading	-2.2
Total of Non-Labor Cost Drivers from 2008 to 2011	**$ 4.0**

Q. How is your testimony organized?

A. First, I provide an overview of Customer Service. Next, I briefly discuss the cost increases in Information Technology (IT). I then discuss write-offs of uncollectible accounts. Finally, I describe other areas of increased costs in Customer Service. The reduction to meter reading and other AMI operating benefits is discussed in PGE Exhibit 300, Section III.

II. Customer Service

A. Overview of Customer Service

Q. Please describe Customer Service.

A. Customer Service is PGE's first point of contact for customers. They communicate with us by placing a phone call (and using the Interactive Voice Response (IVR) phone system), visiting community offices, accessing our website, or mailing a letter. Our mission is to deliver levels of service that our customers require for appropriate levels of satisfaction and costs.

Our success in achieving our mission in the future depends upon our ability to use information and technology to meet our customers' expectations, to continue to target our capital and O&M towards system reliability that our customers value, and to invest in the development of our employees and leaders.

Q. What are PGE's goals for Customer Service?

A. PGE's primary goals for Customer Service include:

- Deliver the value customers require from PGE by ensuring that programs and service options are customer driven; and,
- Ensure that we provide operational excellence in customer service at a reasonable cost.

Q. What measurements does PGE use to ensure operational excellence in Customer Service?

A. As I discuss below in Section B, PGE uses independent third-party customer surveys (such as J.D. Powers and Market Strategies International) as an important form of customer feedback that indicates areas where we are meeting our customers' expectations and areas where we need to improve.

While these surveys provide an important measurement of PGE's service overall, we also measure our performance at the transaction level. PGE conducts online surveys to gather customers' feedback about their experience at our website (www.portlandgeneral.com). Questions range from overall satisfaction with PGE and the usefulness of PGE services to specific questions about the website's ease of navigation, the accuracy of the information received, and whether customers were able to accomplish their primary tasks, such as viewing/paying their bills. Customers can also leave feedback in the comments section.

In addition, we conduct surveys in our community offices and via our IVR system that allow customers to rate their interactions and provide open-ended feedback. The information from this survey data is used to measure the performance of individual customer service representatives (CSRs) on the phones and in our community offices. Customers evaluate CSRs for their courtesy and confidence, correct processing, and information accuracy. In addition, supervisors and "lead" representatives monitor and assess each interaction and provide feedback and coaching to the CSRs.

Monitoring and scoring customer calls and face-to-face transactions captures both the required procedural and the interpersonal aspects of the interaction. These metrics are part of our overall quality assurance efforts and CSRs are held accountable for their performance in these areas, just as they are expected to maintain the percentage of time they are available to speak with customers.

Q. Does PGE consider at-fault complaints part of its operational performance measurement?

A. Yes. The OPUC has established a service quality metric of no more than 57 at-fault complaints company-wide, per year. From 2005 to 2009, our at-fault complaints have remained at 16 or less annually. At-fault complaints are reported throughout the company and the circumstances of each complaint are reviewed for training and process improvement purposes.

B. Customer Research and Feedback

Q. Why is customer feedback important?

A. Customer feedback ensures that our goals are customer driven. PGE has safely and dependably powered northwest Oregon for more than 120 years. During this time, we have developed a solid understanding of our customers' needs. We have also seen significant changes in our customers' expectations, which is why it is as important now as ever for us to maintain open lines of communication and make sure our customer service goals are aligned with our customers' priorities.

Q. How does PGE ensure that customer service goals are customer driven?

A. PGE uses a number of tools and metrics to determine whether customer service goals are customer driven, including:

- Customer ratings from our residential and business customers, where our goal is to be in the top quartile among our peer utilities and all utilities nationally;
- Customer feedback received and reviewed by our Customer Relations team; and
- A customer survey at our Contact Center, with the goal of obtaining real time feedback on our customers' experiences. The survey is optional and immediately

follows the call. It measures satisfaction with PGE, the specific call, and certain qualities of our representatives. We also measure first call resolution,[2] since it is a priority for both our customers and PGE. For calendar year 2008, 95.1% of the customers surveyed felt they were treated as valued customers,[3] and 83.1% indicated they received first call resolution. In 2009, 95.4% of the customers surveyed felt they were treated as valued customers, and 82.1% indicated they received first call resolution.

Q. How does PGE use customer research and feedback?

A. We use customer research and feedback to better understand our customers' unique and diverse needs. As a result, we no longer place customers into just three broad segments (residential, commercial, and industrial). Based upon our experience with customer behavior, customer research and feedback, we classify our residential customers in four market segments and our business customers in 10 industry segments.

PGE uses customer research and feedback to develop comprehensive strategies for responding to customers' changing needs. For example, the online survey provided feedback that our customers wanted outage information on our website. In 2009, we responded with an interactive outage map and outage list that is not only used by our customers, but is also used by the news media covering power outages.

PGE also disseminates this information throughout the company in an effort to educate all areas of the business on customers' concerns and needs. This is extremely valuable as it

[2] First call resolution is based on the percent of customers who indicate that this is the first time they have contacted PGE about a particular problem or question, and that the representative has resolved, or will resolve, that problem or question. The annual score is an average of the monthly first call resolution scores received for that year.

[3] The score for "treated as a valued customer" is based on the percent of customers rating the representative an "8" or "9" on that question ("9" is the highest score).

ensures that PGE and its employees learn from these examples. It also ensures that programs and service options stay focused on customers.

Q. Has PGE developed programs and service options based on feedback from PGE's customers?

A. Yes. Direct customer feedback has led to several programs and service options, including:

- Promotion of paperless bills and renewable options when customers start or transfer service;
- Changes in prorated bill details that allow the full billing details to be displayed;
- Piloting a Customer Feedback form;
- Virtual Hold©;[4] and,
- Implementation of a consolidated bill program for large customers.

PGE is also implementing an Information-Driven Energy Savings (IDES) program. This information tool can reveal energy-reducing strategies that the customer may find valuable to implement. For example, after customers enter their household information, the tool can determine the cost of running a "spare" refrigerator, or identify the cost of "always-on" devices, or determine the bill reduction that would be achieved by setting the thermostat a few degrees lower. IDES is a valuable tool that will allow customers to better manage their household energy usage.

Q. Are there other examples of programs that PGE is implementing to benefit customers?

A. Yes. The Agency Web Portal provides online web access for energy assistance agencies providing support to low income customers. This portal allows agencies (with customer authorization) to view specified customer information and pledge money towards a

[4] The Virtual Hold queuing application allows customers to select a call back from our automated system rather than wait on hold, without losing their place in the queue.

customer's bill. This allows the customer greater privacy, reduces overall time (no phone hold time), and allows agency workers to help more clients.

We have also updated the online process for renewable options enrollment. Previously, when customers signed-up or made changes online, an operations support person would need to re-enter the data into our Customer Information System (CIS) in order to process the request. Depending on the timing of the bill, the operations support person might also have to put the request in queue and follow up later. The updated process automatically enters the information into CIS and coordinates the timing of the processing for 90% of the renewable transactions requested through our website.

In addition, we created a new process and a new entry application for handling renewable enrollment internally that takes what was an average 33-step process down to 3 steps. This reduces the processing time for the customers who call in or enroll at a renewable 'event' (paper) and reduces overall handling and processing time for the Contact Center. Average handling time for requests that were in queue or came from an event declined from 12.9 days to 2.5 days.

Q. Are these programs a result of customers' changing expectations?

A. Yes. Our customers are interested in more service options and these programs and technological enhancements are an effort to meet our customers' expectations.

Q. How are customers' expectations changing?

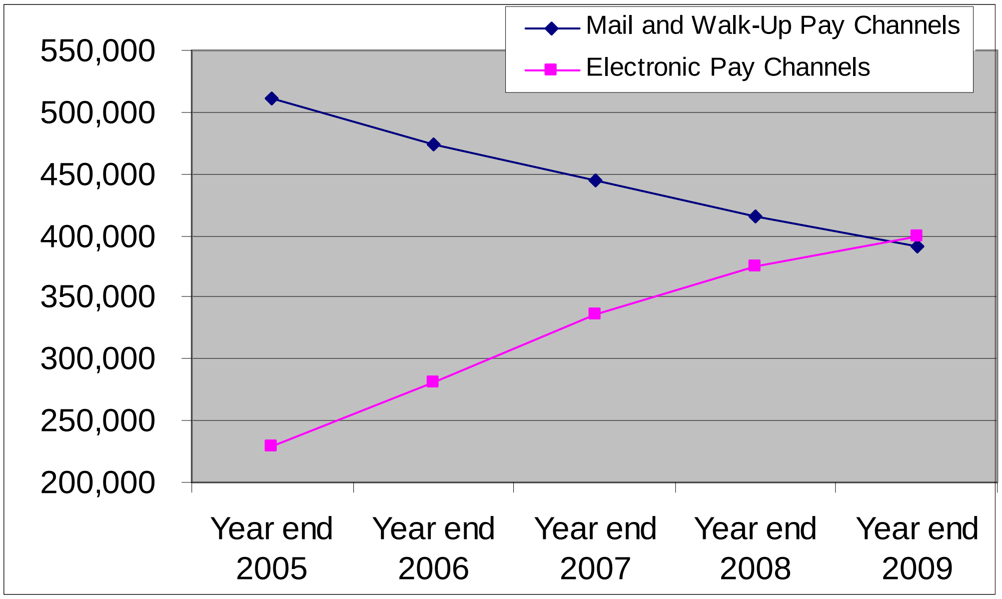
A. Customer expectations are continually changing for all businesses and PGE is no exception. For example, in the 1970s, underground service was not common and was considered a benefit only to customers being directly served by underground lines. Originally, PGE charged a higher underground rate. However, as more customers and communities pushed for underground service, it became the norm in Oregon and was no longer considered a separate benefit.

Today, technology is rapidly changing and with it, customers' expectations. A few years ago, we were neither working with nor communicating with our customers via online portals, but as society and technology has changed, more and more of our customers want to work with us on the web and that is becoming the norm.

PGE must provide customers with options supported by systems that adapt and react to these changes. See also, PGE Exhibit 600. PGE's customers are rapidly adopting new technologies and expect PGE to keep pace. For example, customers want to receive more information from PGE via email and text messages.

Also, customers are now paying their bills differently than in the past. Figure 1 below, shows the significant increase in the number of customers paying their bills electronically (autopay, E-banking through the PGE website or IVR, or phone payments). In fact, the number of customers paying their bills electronically now exceeds those paying by mail or in person. As our customers become more and more technologically dependent, keeping abreast of changing information technology will continue to be an important focus for PGE. It not only meets our customers' needs, but it can also lead to eventual cost savings.

Figure 1



As discussed in PGE Exhibit 203, receiving payments electronically is less expensive than processing checks and this yields operational savings over time. Likewise, both PGE and its customers have more flexibility in responding to emails and text messages than they have with phone calls. While building the capability of responding to customers through different avenues may increase costs in the short run, this can lead to future savings and improved service.

III. Information Technology (IT)

Q. How much are Customer Service IT costs increasing from 2008 to 2011?

A. Costs for Customer Service IT increase by approximately $4.1 million from 2008 to 2011.

Q. What are the primary reasons for the forecasted increase?

A. The primary area of increase is the IT allocated charges that consist of costs for information systems needed to support our operations; IT system replacement costs; increasing cyber security requirements for hardware, software, and network systems; growing data storage requirements; and higher overall costs for maintenance agreements on PGE's systems. These costs are explained in greater detail in PGE Exhibit 600.

IV. Write-offs of Uncollectible Accounts

Q. You identified write-offs of uncollectible accounts (uncollectibles) as another driver of increased costs. How does PGE minimize uncollectibles?

A. PGE minimizes uncollectibles in three ways:

- Actively pursuing fraud, ID theft, and energy theft; for example, by dedicating staff to research fraudulent activities using tools such as LexisNexus, Open Online, Equifax, etc. We also have individuals dedicated to detecting and resolving any situation where the amount of service being provided is not the amount being paid, such as unmetered service, faulty equipment, miswires, theft, tampering, etc. We also have employees dedicated to working directly with customers in fashioning acceptable payment arrangements;
- Reaching out to past due active customers using different channels; for example, by providing bill messages and highlighting past due amounts on bills, making automated outbound calls, sending direct inserts and notices, and maintaining a field collections presence, all of which act as reminders for our customers that they have a bill due or delinquent; and
- Keeping abreast of best practices within the utility industry and incorporating appropriate practices within PGE; for example, by participating in utility conferences and webinars.

Q. What uncollectibles rate is PGE using for 2011?

A. PGE is using a rate of 0.57% for 2011. The light and power component for 2011 is 0.54%, which is an average of the preceding three years of activity. PGE also includes a rate that reflects other write-offs, such as insurance claims related write-offs and other miscellaneous write-offs. This rate is forecasted to be 0.03%, which is based on an average of the preceding three years of activity. The use of a three-year average is beneficial because it smoothes the peaks and troughs in the uncollectibles rate experienced by PGE. Table 2 shows the calculation of our 2011 uncollectibles rate.

Table 2
Uncollectibles Rate ($000s)

	2008 Actuals	2009 Actuals	2010 Forecast	Avg.
Light & Power	$8,072	$8,601	$8,847	
Other	$176	$666	$535	
Revenues	$1,504,002	$1,579,736	$1,598,708	
Uncollectibles Rate	0.55%	0.59%	0.59%	0.57%

Note: Average may not foot due to rounding.

Q. What was PGE's uncollectibles rate in 2009?

A. PGE's actual uncollectibles rate for 2009 was 0.59%. This was in part due to the current economic conditions in Oregon. This includes factors such as the cost of goods (gasoline, food, etc.), and was mitigated in part by additional low income energy assistance funding.

Q. What is the unemployment rate in Oregon?

A. Oregon's unemployment rate has been steadily rising since May 2008 and the average for 2009 was 11.4%. The State of Oregon Department of Consumer and Business Services currently forecasts the following annual unemployment rates: 11.4% for 2010, 10.2% for 2011, and 9.0% for 2012. These state unemployment rates are considerably higher than those experienced as recently as 2007 (5.1%) and 2008 (6.4%).

Q. Is unemployment the only driver of the uncollectibles rate?

A. No. Though there is likely a loose correlation between uncollectibles and unemployment, other contributing factors include things like higher gasoline prices, resetting of adjustable rate mortgages, and higher food costs. These factors affect the employed as well as the unemployed.

Q. Have PGE customers received additional low income energy assistance funding?

A. Yes. For the 2008 to 2009 heating season,[5] Oregon received an additional $21 million of funding (on top of an existing $24 million), of which PGE customers received approximately $4 million. This funding has been extremely important for our customers and has helped keep PGE's uncollectibles rate lower than it otherwise would have been.

Q. Does PGE expect this level of funding to continue in the test period?

A. Not necessarily. Though Congress has approved the same level of additional funding for the 2009 to 2010 heating season, they have not announced the level of funding for the 2010 to 2011 or 2011 to 2012 heating seasons. If the same level of funding is not maintained for each of these two seasons, the 3-year average uncollectibles rate supported in this testimony will be understated.

---

[5] Heating seasons are specifically defined as October 1 to September 30. For example, October 1, 2008 to September 30, 2009.

V. Other Factors

Q. What other factors are increasing costs from 2008 to 2011?

A. The remaining increase is primarily the result of two components: 1) higher amortization expense resulting from more distributed standby generation (DSG), and 2) the absence of insurance proceeds that PGE received related to the major storm in December 2008.

Q. How much of the increase do each of these components account for?

A. The added DSG expense accounts for approximately $250,000 of the increase[6], while the absence of insurance recovery accounts for approximately $140,000. The absence of insurance recovery related to storms is addressed in detail in PGE Exhibit 1000.

Q. Where does PGE discuss reductions to non-labor O&M for meter reading and other AMI operating benefits?

A. The reduction to meter reading and other AMI operating benefits is discussed in PGE Exhibit 300, Section III.

Q. Does this conclude your testimony?

A. Yes.

[6] Additional DSG related O&M expenses are included in PGE Exhibit 700, Section III.

Table of Contents

I. Introduction

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

A. My name is Maria Pope. I am the Senior Vice President, Finance, Chief Financial Officer, and Treasurer at PGE. My qualifications appear in PGE Exhibit 200.

My name is Alex Tooman. I am a Project Manager for Regulatory Affairs at PGE. My qualifications appear in PGE Exhibit 300.

Q. What is the purpose of your testimony?

A. We explain PGE's request for $126.2 million in administrative and general (A&G) costs in 2011 and compare it to 2008 actuals of $118.5 million.

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, such as human resources, accounting and finance, insurance, contract services and purchasing, corporate security, regulatory affairs, legal services, and information technology (IT). We also include other costs such as employee benefits and incentives, support services, and regulatory fees that fall within the FERC definition of A&G. PGE Exhibit 1001 provides a list of A&G functions plus a summary of costs and full time equivalent (FTE) employees for 2006 (actuals) through the 2011 (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	**2008 Actuals**	**2011 Forecast**	**Annual Average % Change**
Facilities/General Plant Maintenance	10.7	11.0	1.0%
Accounting/Finance	7.9	8.8	3.7%
HR/Employee Support/Ethics and Compliance	7.6	5.9	-7.8%
Insurance, Injuries and Damages, etc.	11.9	10.5	-3.9%
Legal	7.4	7.7	1.3%
Federal and State Regulatory Affairs	2.4	2.5	2.1%
Corporate Governance	3.1	3.4	2.5%
Business Support Services	2.1	2.5	4.7%
Environmental Programs	1.1	1.6	15.6%
Corporate R&D	0.2	0.8	49.0%
Contract Services/Purchasing	1.1	1.1	1.4%
Security and Business Continuity	1.3	1.5	4.5%
Corp Communications/Public Affairs	2.1	1.9	-3.2%
Load Research	0.2	0.2	7.4%
Hydro Licensing	0.5	0.5	0.5%
Performance Management[1]	1.1	1.2	1.9%
Governmental Affairs	1.1	1.3	6.9%
Total for Major Functional Areas	**61.5**	**62.3**	**0.4%**
IT: Direct & Allocated	7.6	11.9	16.3%
Labor Cost Adjustment	0.0	(2.5)	N/A
Other Service Providers to A&G	0.4	0.4	2.8%
Benefits (net of capital allocs.)	29.9	43.7	13.6%
PTO Loadings to A&G	4.2	4.6	3.3%
Incentive Plans (net of capital allocs.)	15.5	5.9	(27.7%)
Other Membership Costs	1.5	2.1	5.4%
Miscellaneous	0.1	0.2	23.2%
Total Other A&G Costs	**59.0**	**66.3**	**3.9%**
Regulatory Fees	**6.3**	**7.4**	**5.4%**
Capitalized A&G	(6.5)	(7.6)	5.4%
Duplicate Charge Offset	(1.9)	(2.1)	3.6%
Total A&G	**118.5**	**126.2**	**2.1%**

Q. Table 1 shows A&G expenses have increased by approximately $7.7 million from 2008 to 2011. What are the main reasons for this increase?

A. There are six primary reasons for the higher costs in 2011:

- Increasing benefit costs (discussed in PGE Exhibit 500);

[1] Actual costs normalized to reflect shift from Customer Accounting and Distribution to A&G with no change to PGE's corporate costs.

- Higher insurance costs and retained losses;
- New projects for research and development;
- Increasing membership costs for PGE's participation in the Western Electricity Coordinating Council (WECC);
- Increasing requirements for environmental services; and
- Higher levels of IT costs.

Q. How would you characterize the forecasted increase in A&G costs from 2008 to 2011?

A. On the whole, if health care costs are removed, the increase is very limited. For A&G functional areas, the average annual rate of increase is only 0.4%, which is less than the rate of inflation. For other A&G costs, the increase is somewhat larger due to cyber security and IT systems replacement requirements, but is overwhelmingly driven by higher health care costs.

Q. How is your testimony organized?

A. In the next section, we discuss the major cost drivers by A&G function. We then provide detail regarding increases in other A&G costs, particularly the WECC membership and IT.

II. Major Cost Increases by A&G Function

A. FTEs

Q. Do you have any increases associated with new employees?

A. Yes, but the increase is minimal. As discussed in Section II of PGE Exhibit 500, we have significantly limited the increase in FTE positions as reflected in the 2011 test year forecast. Overall, PGE's net change in FTEs from 2008 to 2011 is a reduction of 82.7 FTEs. However, if we remove the effects of PGE's Advance Metering Infrastructure (AMI) program, then there is an increase of 33.5 FTEs. The overall effect on PGE is a forecasted 0.45% annual increase from 2008 to 2011 (with AMI normalized). For A&G specifically (not including IT, which is discussed in PGE Exhibit 600), we forecast an increase of only 3.3 FTEs, which represents a 0.32% annual average increase.

B. Benefits

Q. By how much do you forecast benefit costs to increase from 2008 to 2011?

A. The increase in benefit costs from 2008 to 2011 is approximately $13.9 million and includes such items as health and dental plans, 401(k) plan, workers' compensation, and employee life and disability insurance.

Q. How do you explain this increase?

A. The wage, incentive, and benefits-related costs are discussed in detail in PGE Exhibit 500, which explains how they are affected by increases in medical, pension, and compensation costs necessary for PGE to remain competitive in a labor market for specialized and qualified applicants. The benefit amounts in Table 1 represent the "net" changes within A&G only, as compared to the gross costs applicable to corporate PGE. Net A&G refers to the amount remaining in A&G after labor loadings apply certain amounts of these costs to capital projects and "below-the-line" activities. PGE Exhibit 500 explains the gross corporate forecast for these costs.

C. Insurance

Q. What types of insurance coverage does PGE maintain?

A. PGE maintains several types of insurance coverage, which we list and describe in PGE Exhibits 1002 (confidential) and 1003. In general, there are three types of insurance: Property, Liability, and Miscellaneous. We also discuss retained losses.

Q. What is PGE's forecast of insurance premiums for 2011?

A. As shown in Table 2 below, insurance premium costs are expected to be $9.6 million in 2011, increasing from $8.5 million in 2008. The primary drivers of the increases are property and liability coverage. The 7% increase in property premiums is due to an increase in PGE's Total Insured Value (TIV), capital additions, and increases in premium rates. The liability program is expected to see rate increases affecting PGE's general liability, directors and officers liability (D&O), and fiduciary liability coverage.

Table 2
Insurance Premiums ($ millions)

Type of Policy	2008	2011	Annual Average % Increase
Property	$4.4	$4.7	2.2%
Liability	$3.9	$4.6	5.7%
Miscellaneous	$0.22	$0.28	8.4%
Total	**$8.5**	**$9.6**	**4.1%**

Q. What is PGE's forecast of retained losses for 2011?

A. PGE's retained losses increase $0.7 million from 2008 to 2011. Auto and General Liability retained losses account for most of that increase.

Table 3
Retained Losses ($ millions)

Type of Loss	2008	2011	Annual Average % Increase
Workers' Compensation	$1.8	$1.9	1.8%
Auto & General Liability	$1.2	$1.7	12.3%
Total	**$3.0**	**$3.6**	**6.3%**

We discuss retained losses in more detail below.

PGE's Insurance Policies

Q. How does PGE determine the appropriate amount of coverage limits?

A. In general, PGE purchases insurance to provide adequate financial protection from loss exposures that otherwise could result in an adverse material effect on PGE's results of operations. For certain lines of coverage, limit requirements are determined by regulatory bodies. PGE also consults with insurance brokers and other subject-matter experts concerning appropriate limits. Benchmarking studies and utility peer group comparisons are reviewed to ensure that PGE's practices for purchasing insurance are consistent with utility industry practice.

Q. How does PGE structure its coverage limits for the various types of insurance purchased?

A. Within the utility industry, the ability to sufficiently insure a loss exposure often requires capacity that is beyond the underwriting ability of a single insurer. To acquire adequate coverage limits and diversify exposure (so as to not excessively rely on any one carrier), an insurance structure is assembled whereby the primary insurer provides specific coverage terms and capacity limits, however, less than that 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" denotes that the layer is supplemental to and attaches to the underlying layer to form a single cohesive insurance program. In structuring coverage this way, PGE is able to secure the adequate level of insurance capacity needed to protect against the adverse effects of severe losses with competitive pricing, as well as to diversify exposure to any one carrier.

Q. How does PGE forecast its insurance premium costs?

A. PGE bases its estimates on the most recent data for its insurance program, adjusted to account for:

- Amount and type of property or potential losses;
- Trends in insurance pricing and capacity provided by insurers, insurance brokers, consultants, and industry analysts;
- Changes expected in its various insurance programs in the coming years, such as increases or decreases in limits purchased, or property being added (such as Biglow Canyon Wind Farm) 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.

Current Trends

Q. What are the current trends in the insurance industry?

A. The overall insurance market in 2009 has remained relatively stable with prices moderating on certain lines of coverage while other lines remained flat. However, there are other trends related to specific lines of insurance coverage, such as property insurance, general liability, and D&O liability.

Q. Please discuss the trends in the area of property insurance.

A. The property insurance market experienced increases during the first half of 2009, with rates increasing on average approximately 5%.[2]

Q. What are the trends for general liability insurance?

A. The overall market for general liability insurance has experienced minimal increases in premiums. However, utilities have experienced general liability premium increases, generally in the range of 10% to 30%.[3] These increases have been driven primarily by catastrophic utility industry losses (e.g., California wildfire losses, the Tennessee Valley Authority coal ash spill, and Missouri's Taum Sauk dam breach) that have created a perceived increase in risk profiles by many insurance underwriters.

Q. What are the trends for D&O liability insurance?

A. Outside the financial services sector, D&O coverage has remained competitive with broad terms and conditions, stable capacity, and relatively flat rates.

Property Insurance

Q. You noted above that there was a general trend of insurance rates increasing approximately 5%. Does this trend explain the increase in property insurance costs?

A. Yes, but only partially. As seen in Table 4 below, PGE's overall property insurance[4] premiums are forecasted to increase by approximately $0.3 million from 2008 to 2011 because PGE did not elect to purchase property insurance for its transmission and distribution system in 2011, as we discuss below. We are seeking an alternative recovery mechanism for recovery of storm-related damages to transmission and distribution property in 2011.

---

[2] Willis, Marketplace Realities & Risk Management Solutions 2010.
[3] Marsh, U.S. Insurance-Market Report 2009.
[4] Property insurance is comprised of All-Risk, Biglow Operational Risk and Biglow Builder's Risk, Crime, and T&D.

Table 4
Property Insurance Premium Increase
($ millions)

	2008	2011	Annual Average % Increase
All-Risk	$2.1	$3.4	17.1%
Biglow *	0.7	1.3	21.0%
Crime	0.06	0.03	(19.2)%
T&D (storms)	1.5	0.0	100.0%
TOTAL	**$4.4**	**$4.7**	**2.3%**

* Includes Operational Risk and Builder's Risk

As seen in Table 4 above, the All-Risk total premiums increase $1.3 million from 2008 to 2011. This increase is due to premium increases of 13.6% and total insured value increases (TIV, i.e., plant additions and asset valuation) of approximately 25% from 2008 to 2011. The Biglow Canyon Wind Farm premium increased $0.56 million due to an increase of approximately $738 million in TIV.[5]

Q. Please explain why PGE is not purchasing insurance for its transmission and distribution property in 2011.

A. Renewing or purchasing insurance for physical loss and damage to transmission and distribution property (poles and conductor) is not economic at this time. PGE's current insurance policy will end October 31, 2010. However, after the winter storm in December 2008, PGE exhausted the maximum amount of insurance recovery under the policy. Therefore, there are no further insurance proceeds on the policy if another insurable storm event occurs. Additionally, PGE was unable to acquire replacement coverage with similar terms and conditions. Consequently, PGE has chosen to seek an adjustment mechanism which we discuss in PGE Exhibit 800.

General Liability

Q. Please describe the premium increases in PGE's liability coverage.

[5] Phase 2 was in service August 2009 and Phase 3 will be in service September 2010.

A. General liability insurance covers PGE's liability from claims resulting from bodily injury or property damage arising out of PGE's operations, including the use of company vehicles. Given PGE's contact with its customers' premises and the dangerous nature of its operations, this insurance is of paramount importance. Premiums in PGE's general liability program are expected to increase overall by 18% from 2008 levels, driven primarily by the increase in excess liability coverage. As we note above, this increase is primarily due to recent catastrophic losses experienced in the utility industry that are now manifesting themselves in increased premiums as insurers seek to recover their losses by increasing their rates on existing accounts.

Table 5
General Liability Premium Increase
($ millions)

Coverage	2008	2011	Average % Increase
D&O	$1.5	$1.6	2.2%
Fiduciary	0.1	0.1	1.0%
Excess Liability	1.8	2.1	5.3%
Miscellaneous *	0.4	0.7	20.5%
Total	**$3.9**	**$4.6**	**5.7%**

* Miscellaneous includes Excess Workers' Comp, Cyber, and Nuclear

Q. Is D&O insurance coverage important?

A. Yes. D&O liability insurance shields PGE's directors and officers against normal, but sometimes significant, risks associated with managing the business. D&O insurance protects shareholders and customers from the consequences of financial distress and customer claims. Maintaining D&O insurance is necessary to attract and retain qualified and competent directors and officers. The limits purchased are consistent with the standard practice of the utility industry.

Retained Losses

Q. What method does PGE use to forecast workers' compensation, auto liability, and general liability losses?

A. PGE engages the services of an independent actuarial firm every year to provide loss projections related to workers' compensation, auto liability, and general liability losses. There is an inherent uncertainty associated with predicting loss events both in terms of frequency of occurrence and severity of loss. The actuarial firm assembles and analyzes data (over the past 10 to 20 years) to estimate the probability and likely cost of the occurrence of workers' compensation, auto liability, and general liability loss events.

Q. Why does PGE purchase workers' compensation insurance?

A. The State of Oregon requires PGE to maintain coverage in excess of its self-insured deductible to protect itself from catastrophic losses to employees arising out of and in the course of employment.

Q. Please discuss the increase to excess workers' compensation and auto and general liability potential losses.

A. As shown in Table 6 below, retained losses are forecasted to increase by almost 20% between 2008 and 2011. However, most of this increase is due to an abnormally low level of auto and general liability losses in 2008.

Table 6
Retained Losses
($ millions)

	2008	**2011**	**% Increase '08-'11**
Worker's Comp	1.8	1.9	2.1%
Auto & General Liability	1.2	1.7	46.3%
Total	**3.0**	**3.6**	**19.4%**

Q. Why were auto and general liability losses abnormally low in 2008?

A. Auto liability losses in 2007 and 2009 were $305,000 and $268,000. For 2008, these losses were only $82,000, which is significantly below the surrounding years. For 2011, auto liability losses are forecasted at approximately $300,000, close to historical losses.

A similar story can be told regarding general liability losses. In 2007, general liability losses were $2.6 million but only $1.1 million in 2008. For 2011, losses are forecasted at approximately $1.4 million.

D. Research and Development

Q. What are PGE's forecasted 2011 costs for PGE's corporate research and development (R&D) activities?

A. For 2011, we forecast approximately $760,000 in R&D expenses for 12 selected projects, which are necessary to address the significant changes and new technologies facing PGE and the industry. These projects primarily relate to renewable energy, energy efficiency, and generation and are summarized in Table 7 below (for additional detail listing descriptions and benefits for R&D projects, see PGE Exhibit 1004):

Table 7
Summary of 2011 R&D Projects

Project	Cost
• Distributed Resources Process & Reporting Improvements – would help automate PGE's feeder queue for tracking, maintaining and integrating small energy production sites.	$150,000
• Demand Response Com Model – this project is to research demand response requirements, formulate a communications model, and work with RFP winning bids for commercial demand response.	$50,000
• Firm Load Reduction Technology Demonstration – PGE will participate in this project to determine feasibility of various applications that yield overall system load reductions.	$150,000
• Relay Control Equipment for Residential Direct Load Control – PGE will explore how customers (or their in-home energy infrastructure) will respond to direct load control opportunities.	$100,000

• EPRI Target P75.002 Mercury & Integrated Environmental Control Technology Development – This research will help PGE address the technical requirements for mercury control as a retrofit at the Boardman plant.	$73,095
• Geologic Sequestration of CO_2 in Columbia River Group Basalts – PGE is a member of the Big Sky Carbon Sequestration Partnership with particular interest in geologic sequestration in basalt. This project continues a deep injection test demonstration which began in 2009.	$10,000
• Oregon State University (OSU), Carbon Balance for Capture of Flue Gas Greenhouse Gases by Microalgae – PGE and Oregon State University continue the exploration of using fossil fired power plants to capture CO2 with algae & convert to liquid fuel.	$5,000
• Agronomy, Acceptability & Potential for Growing Giant Cane (Arundo donax) in Eastern Oregon. This project investigates giant cane as an energy crop and possible coal substitute at Boardman power plant in Eastern Oregon.	$114,000
• OSU Wave Energy Research – Wave Energy Linear Generators - PGE is helping Oregon State University (OSU) advance a unique power generating device that relies on the vertical movement of ocean waves. This project continues that support.	$5,000
• Home Energy Management – allows PGE to further investigate competing approaches based on smart grid advances.	$75,000
• Short-term Energy Storage Devices with Local Network Systems – this project allows PGE to investigate small neighborhoods or communities where energy use is reasonably matched to a limited, but well stored (cost-effectively) energy supply.	$10,000
• Biglow Canyon Wind Farm – this project subscribes to the support and expertise afforded by OSU researchers to help advance efficient output of PGE's Biglow Canyon Wind Farm.	$10,000

Q. How will the 2011 R&D projects benefit customers?

A. First, many of the projects are leveraged financially by working with other utilities to sponsor shared R&D. This means that PGE contributes a fraction of the overall research costs, but will receive 100% of the benefits. PGE will work with several universities on shared projects that support unique, regional renewable power research such as wave, wind, solar, biomass, and CO_2 capture and sequestration. Finally, each project will provide specific benefits. For example, PGE is pursuing research into growing, charring, and combusting giant cane (*Arundo donax*) as a substitute for coal. Giant cane is a renewable biomass fuel, that if proven cost-effective, could be used as a fuel to allow continuation of

Boardman as a baseload power resource. This would significantly help PGE meet Oregon's renewable energy standard, while reducing PGE's overall carbon footprint.

Q. How have PGE's customers benefited from R&D in the past?

A. Two examples indicate how PGE customers benefited from R&D projects:

- Dispatchable Standby Generation (DSG) began as an R&D project that allowed PGE access to additional sources of capacity during peak loads. At year end 2009, there are 37 generators (48 MW of capacity) through DSG. In 2010, we expect to add 19 additional generators totaling 75.2 MW of capacity.
- The installation of special fencing systems at 30 substations also began as R&D and resulted in the virtual elimination of animal-caused outages in these substations. This is described in more detail in PGE Exhibit 1005.

Q. What are the risks of not participating in the proposed research projects?

A. As noted in PGE's 2009 Integrated Resource Plan, PGE must maintain high standards of safety and reliability in its portfolio of resources. As customer loads grow, PGE must continue to add resources to its system. By increasing funds to R&D programs, we will be proactive, rather than reactive, to evolving technologies and regulation (e.g., using charred-biomass renewable fuel). By supporting demonstration projects and activities with other research groups (e.g., EPRI, national laboratories, and universities), PGE will avoid missing opportunities to participate and direct how resources are developed for maximum customer benefit.

PGE must continue involvement with, and provide support for, projects of increasing importance such as demand response and carbon offsets/reductions. PGE must keep abreast of issues that remain under continued public scrutiny and may significantly benefit customers. PGE will use R&D funds to improve operation and maintenance of its generation and distribution systems and participate in opportunities to review and apply proposed system improvements through demonstration projects. PGE's participation in demonstration projects, trade programs, and specific-issue research has proven valuable to PGE's customers over the long run.

E. Environmental Services

Q. By how much do you expect environmental service costs to increase from 2008 to 2011?

A. We forecast that environmental service costs, as charged to A&G, will increase from $1.1 million in 2008 to $1.6 million in 2011. This increase is primarily due to expanding regulatory requirements (at federal, regional, state, and local levels) related to climate change and other environmental issues.

Q. Why specifically have these costs increased?

A. Environmental expenditures are increasing due to new regulations or modifications to existing regulations such as site certificates and permit and license requirements issued by the Oregon Energy Facility Siting Counsel (EFSC), Oregon Department of Environmental Quality (ODEQ), and Federal Energy Regulatory Commission (FERC) plus other requirements enacted by the EPA and other federal agencies. Additional compliance activities relate, but are not limited, to the following PGE locations: Biglow Canyon for wildlife monitoring; Oak Grove, North Fork, Faraday, River Mill, Sullivan Plant for fisheries, wildlife, and water quality license requirements; Beaver/Port Westward Generating Sites for air quality and waste management/disposal; and Pelton Round Butte for the Fish Health Management Program, which involves studying fish populations and potential changes in the distribution of fish disease agents associated with the new fish facilities at the site. Specific examples of those requirements (that did not exist in 2008) involve:

- Clackamas Hydro project – a new FERC license includes a significant number of regulatory requirements pertaining to protecting, improving, and monitoring the environment including fish, wildlife, and water quality. Many of these requirements become effective in 2011 and require substantial costs for materials, equipment, laboratory work, temporary labor, and professional services.
- Climate Change – new state and federal monitoring and reporting requirements for greenhouse gas emissions with third party verification beginning in 2010.
- Environmental Emergent Fund – beginning in 2010 for unanticipated/unplanned cleanup costs including emergencies that are a result of a change in environmental requirements and/or regulation.

Q. Does this comprise all of the environmental costs charged to PGE?

A. No. The majority of environmental costs will be incurred as part of Generation O&M. For detail on environmental compliance requirements, projects and expenditures, see PGE Exhibit 700.

III. Other A&G Costs

A. Membership Costs

Q. Please explain the increase in the membership costs from 2008 to 2011.

A. PGE's other membership costs are forecasted to increase from approximately $1.5 million (for 2008 actuals) to approximately $2.1 million in 2011. Membership costs for the WECC and the Northern Tier Transmission Group (NTTG) account for this increase.

Q. Please explain the increase in WECC membership cost from 2008 to 2011.

A. WECC membership costs are projected to increase from approximately $740,000 in 2008 to approximately $1.2 million in 2011. This increase is the result of additional compliance and regulatory oversight costs, which include the following items:

- Increasing WECC Compliance Enforcement costs – relates to additional WECC staffing and the associated costs of registering entities, investigations, reviews of self-certifications, expanding scope of both the on-site and off-site audits, plus other Compliance Monitoring & Enforcement Program activities. The expansion in scope is mainly due to an increase in the number of standards for WECC to monitor.
- Higher costs for the Reliability Assessment and Performance Analysis Program – reflects the necessity of addressing increasing deployment of variable resources (e.g., wind and solar) and the need to better integrate various planning and resource assessment functions.
- Increasing facilities costs to accommodate significantly expanding WECC staff.
- Additional legal and regulatory staff – represents additional support needed to monitor 470 registered entities under the Compliance Monitoring and

Enforcement Program, which requires significant legal support for drafting, reviewing, and negotiating.

Q. What is the NTTG?

A. The NTTG is composed of transmission providers and customers that actively purchase and sell transmission capacity on the Northwest and Mountain States grid. The group, "coordinates individual transmission systems operations, products, business practices, and planning of their high-voltage transmission network to meet and improve transmission services that deliver power to consumers."[6] PGE participates in the NTTG along with the following utilities: Deseret Power Electric Cooperative, Idaho Power, NorthWestern Energy, PacifiCorp, and Utah Associated Municipal Power Systems.

Q. Please explain the increase in NTTG membership cost from 2008 to 2011.

A. PGE's NTTG membership costs will increase from approximately $78,000 in 2008 to $197,000 in 2011, which is approximately $100,000 lower than originally projected as a result of PGE negotiations. NTTG costs reflect PGE's share of the group's budget.

B. Information Technology

Q. How much does PGE forecast allocated IT costs will increase for A&G?

A. Between 2008 and 2011, PGE forecasts that IT charges to A&G will increase by approximately $4 million.

Q. Do these represent all the IT charges to A&G or all the IT costs for PGE?

A. These represent the IT charges to A&G and are only a portion of the total IT costs incurred for PGE as a whole. As noted in PGE Exhibit 600, A&G receives two types of IT costs: 1) directly charged, and 2) allocated.

[6] http://www.nttg.biz/site/

Q. What is the difference between direct and allocated charges?

A. 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 ledger accounts related to those operations. Other IT work that is performed on voice, data, network, communications, and office systems are not the direct responsibility of one specific operating area. Instead, these costs apply broadly to all of PGE activities and departments and are first charged to a balance sheet ledger account and then allocated to the expense ledger accounts of the various functional areas. Labor charges to the balance sheet ledger account have labor loadings applied per PGE's loading and allocation policies.

Q. What are the primary reasons these costs are forecasted to increase?

A. The primary area of increase is in the allocated charges that consist of increasing cyber security requirements for hardware, software and network systems; growing data storage requirements, higher overall maintenance costs on PGE's systems; and, the IT system replacement program. These costs are explained in greater detail in PGE Exhibit 600.

Q. Does this complete your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
1001	Summary of A&G Costs
1002C	**Summary of Insurance Policies/Premiums**
1003	Description of Insurance Coverage
1004	2011 R&D Project Detail
1005	R&D Project Benefits

A&G Summary	$ Millions						$ Change	Annual	FTEs							
Category	2006 Actuals	2007 Actuals	2008 Actuals	2009 Forecast	2010 FOM	2011 FOM	2008 to 2011	% Change	2006 Actuals	2007 Actuals	2008 Actuals	2009 To Date	2010 FOM	2011 FOM	2008 to 2011	% Change
Major Functional Areas																
Facilities and General Plant Maintenance	10.4	10.4	10.7	10.9	10.7	11.0	0.3	1.0%	14.4	13.6	14.1	13.3	11.5	11.5	(2.6)	-6.6%
Accounting/Finance	9.1	8.1	7.9	8.3	8.3	8.8	0.9	3.7%	76.6	77.6	76.7	78.7	79.7	79.7	3.0	1.3%
HR/Employee Support (net of capital allocs.)	5.6	5.5	7.6	5.9	5.8	5.9	(1.6)	-7.8%	87.1	98.9	99.4	99.5	102.9	105.1	5.7	1.9%
Insurance / I&D	6.7	9.4	11.9	9.3	11.9	10.5	(1.3)	-3.9%	6.2	6.4	6.4	6.2	7.0	7.0	0.6	2.8%
Legal	5.9	5.9	7.4	6.0	6.7	7.7	0.3	1.3%	25.3	25.4	28.2	29.0	30.6	30.6	2.3	2.7%
Regulatory Affairs	2.7	2.3	2.4	2.2	2.5	2.5	0.2	2.1%	29.6	28.5	28.6	26.6	29.0	29.0	0.4	0.4%
Corporate Governance	2.6	2.8	3.1	3.1	3.3	3.4	0.2	2.5%	15.4	17.6	15.1	14.4	16.1	16.1	1.0	2.2%
Business Support Services	2.4	2.2	2.1	2.4	2.4	2.5	0.3	4.7%	8.1	8.1	7.9	7.8	8.0	8.0	0.1	0.5%
Environmental Services	1.0	0.9	1.1	1.1	1.5	1.6	0.6	15.6%	-	-	-	-	-	-		
Corporate R&D	0.2	0.3	0.2	0.4	0.4	0.8	0.5	49.0%	-	-	-	-	-	-		
Contract Services/Purchasing	1.0	1.0	1.1	1.1	1.1	1.1	0.0	1.4%	11.0	19.4	21.2	21.0	21.0	21.0	(0.2)	-0.3%
Security and Business Continuity	0.7	1.0	1.3	1.5	1.5	1.5	0.2	4.5%	4.8	6.1	7.0	8.2	9.0	9.0	2.0	8.8%
Corp Communications/Public Affairs	1.6	2.1	2.1	1.9	1.8	1.9	(0.2)	-3.2%	18.4	21.9	19.3	21.0	21.8	21.8	2.5	4.1%
Load Research	0.1	0.1	0.2	0.2	0.2	0.2	0.0	7.4%	-	-	-	-	-	-		
Hydro Licensing	0.3	0.4	0.5	0.4	0.4	0.5	0.0	0.5%	-	-	-	-	-	-		
Performance Management (a)	1.0	1.1	1.1	1.0	1.1	1.2	0.1	1.9%	12.0	13.2	13.5	13.1	12.6	12.6	(0.9)	-2.2%
Governmental Affairs	1.0	1.0	1.1	1.2	1.3	1.3	0.2	6.9%	12.4	10.9	12.1	13.7	12.3	12.5	0.4	1.2%
Subtotal	52.1	54.6	61.5	56.8	60.9	62.3	0.7	0.4%	321.2	347.7	349.5	352.5	361.4	363.9	14.4	1.4%
Other A&G Costs																
IT: Direct & Allocated	6.8	7.1	7.6	8.1	8.4	11.9	4.3	16.3%	263.2	268.8	271.6	276.1	287.4	296.4	24.8	3.0%
A&G/IT Labor Cost Adjustment		-	-	(0.5)	(1.9)	(2.5)						(4.5)	(11.9)	(27.6)	(27.6)	
Unapplied Corporate Cost Adjustments	-	-	-	(0.8)	(13.0)	-										
Other Service Providers to A&G	0.3	0.3	0.4	0.4	0.4	0.4	0.0	2.8%								
Benefits (net of capital allocs.)	28.7	30.9	29.9	33.5	34.1	43.7	13.9	13.6%								
PTO Loadings to A&G	3.9	3.9	4.2	4.3	4.6	4.6	0.4	3.3%								
Incentives (net of capital allocs.)	8.9	19.5	15.5	5.8	10.6	5.9	(9.6)	-27.7%								
Severance	-	-	-	0.1	1.8	-	-	0.0%								
Regulatory Fees	3.1	4.2	6.3	6.5	6.5	7.4	1.1	5.4%								
Other Membership Costs	0.5	0.7	1.5	1.6	2.1	2.1	0.6	12.3%								
Miscellaneous	0.3	0.3	0.1	0.7	0.0	0.2	0.1	23.2%								
Subtotal	52.5	66.7	65.3	59.7	53.7	73.6	8.3	4.1%								
A&G Offsets																
Capitalized A&G	(6.4)	(6.6)	(6.5)	(7.2)	(6.6)	(7.6)	(1.1)	5.4%								
Duplicate Charge Offset (b)	(1.7)	(1.8)	(1.9)	(2.1)	(2.1)	(2.1)	(0.2)	3.6%								
TOTAL A&G (c)	96.6	112.9	118.5	107.3	105.7	126.2	7.7	2.1%	584.4	616.5	621.1	624.1	636.9	632.7	11.6	0.6%

Notes:
(a) Actual costs normalized to reflect shift from Customer Accounting and Distribution to A&G with no change to PGE's corporate costs.

PGE's Insurance Policies

Insurance Policy	Description
All Risk Property	PGE’s main property insurance program insures 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
Biglow Canyon Wind Farm	Insurance for Biglow Canyon Wind Farm consists of two policies: 1) Operational All-Risk coverage for Biglow 1 and 2 wind turbine projects are insured to their full replacement values; 2) Biglow 3, which is currently under construction, is insured under a Builders’ Risk policy. The Builders Risk coverage will cease upon completion of Biglow 3, expected in September 2010.
Solar Projects	PGE is currently a managing member and operates two solar project; Sunway 1 and Sunway 2. Sunway 3 is under development and will be finished in 2010. PGE maintains separate insurance coverage for its two operating solar projects each consisting of a Package policy (Property and General Liability) covering the physical assets and liability associated with its operation. Also, there is Automobile Liability and Umbrella Liability for each. Sunway 3’s construction phase is currently insured by the contractor.
Directo's and Officers Insurance	Directors and Officers (D&O) Liability Insurance shields PGE’s directors and officers against the normal risks associated with managing the business. The lack of an appropriate level of D&O insurance would make it difficult for PGE to hire and retain qualified and competent people for positions at the director and officer level. PGE’s D&O insurance protects the Company’s balance sheet from losses incurred due to lawsuits against the Company and its directors and officers for wrongful acts. This protects shareholders and ratepayers alike from the consequences of financial distress.
Auto and General Liability	Excess 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.
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.
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.

Insurance Policy	Description
Pelton Auto Policy	The Pelton Round Butte Primary Automobile Liability only covers PGE's vehicles at the Pelton Round Butte hydro electric projects. The Confederated Tribes of the Warm Springs Reservation of Oregon (Tribes), as a project co-owner, did not feel comfortable with the $2 million deductible maintained on PGE's General and Auto Liability coverage. Therefore PGE agreed to maintain a separate primary auto liability policy with no deductible.
Aviation	This policy insures the helicopters' hull values from physical damage and provides liability coverage in operating the aircrafts during PGE's line patrol operations.
Network Security & Privacy Liability (Cyber)	The policy has several components insuring risks such as (1) broad privacy liability where there is a breach of personal identifiable information, personal health information and corporate confidential information, (2) network security liability protecting against damage to 3rd party data, software or programs caused by malicious code or denial of service attacks, and (3) media liability protecting against publishing or other content risks (copyright, trademark).
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. This coverage is typically excluded under most All-Risk Property policies and must therefore be purchased under separate cover.
Excess Worker's Comp	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.
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.
Surety Bonds	In the course of doing business PGE must procure and maintain various surety bonds throughout the year. These bonds allow PGE to do work for various state and city governments and agencies as well as a requirement for maintaining a form of collateral for self-insuring its workers' compensation obligations.
Liquor Liability	This policy is related to one of PGE's subsidiaries, Salmon Springs Hospitality Group, which provides catering services including the sale and serving of alcohol. In order to maintain its alcohol license the Oregon Liquor Control Commission requires Salmon Springs to maintain Liquor Liability insurance coverage in order to serve alcohol.

R&D Projects Scheduled for 2011

Project Title (Requested Projects include Multi Year)	2011 Approved Projects
Distributed Resources Process & Reporting Improvements Description: With all the new requirements placed on Distributed Resources (Solar Initiative, Feed-In Tariff, Demand Response Controls, WREGIS), PGE needs to modify and automate its work processes to remain at near existing staffing levels. An example of updating and automation would be linking our GenOnSys system with our Maximo Maintenance system so that when a particular type of alarm came into GenOnSys, it would automatically generate a work order. This project will also help automate PGE's feeder queue for tracking solar projects, small power projects and DSG as well as establish a standard system for providing information to the Protection Department for customers wanting to interconnect with PGE on distribution feeders. Benefit: This project will determine whether a proposed automated solution is cost effective. It will provide improved response to alarms at Distributed Resources sites, reducing system outages and improving availability. The project allows PGE greater flexibility in responding to customer needs when interconnecting with distribution feeders. Risks of Non-Participation: DSG labor costs will increase due to current manual processes and potential inappropriate customer charges for feeder upgrades could be levied on the wrong customers.	$150,000
Demand Response Com Model Description: For this project, the use of an integrator like Factory IQ will model the newly approved Schedule 77 Demand Response tariff following the communication standard 61850-7-420. This standard has elements developed for distributed generation but not demand response and is one of the cornerstone standards being reviewed by NIST as a potential smart grid interoperability requirement. The project would research the Demand Response requirements and formulate a communications model (Com Model) that can be implemented in our GenOnSys software that's used for controlling our generators, only this will monitor and control our load reductions for Schedule 77 and our RFP winner for commercial demand response. Benefit: By creating a standardized model for Demand Response, PGE will benefit from both the labor associated with bringing a new Demand Response client into the program as well as setting standards for information transmission related to Demand Response. Risks of Non-Participation: Costs associated with each new Demand Response installation will be variable as well as the data and requirements for each Demand Response customer will also vary.	$50,000
Firm Load Reduction Technology Demonstration Description: PGE is proposing collaboration with a provider of control equipment targeting commercial building lighting and HVAC to demonstrate automatic peak load reduction. The funds will be used to purchase the control equipment and communications equipment to test the capacity impact of automatically and seamlessly reducing load during critical system peaks. Testing includes sending signals to control systems, receiving acknowledgement of the signal, monitoring the automatic reduction of load without human intervention, and observing immediate feedback to system operations of the amount of reduction. The impact on automated notification systems, collection of usage determinants, billing and customer satisfaction will also be examined for any system changes that will be required for full scale implementation of Auto Demand Response (DR). This research and partnership supports PGE representations made as part of the OPUC AMI filing - to implement firm peak load reductions. Benefit: Approving this request will help offset some equipment cost for PGE participants. It is expected that PGE funds will be supplemented with the provider's installation services and software hosting. Results will be used in integrated resource planning, Distributed Resources Command Center (DRCC) development, cost	$150,000

effective demand response capability, and power operations. Risks of Non-Participation: Benefits in this specific application will quantified against market pricing and the cost of building a peaking plant for a limited number of hours of operation.	
Relay Control Equipment for Residential Direct Load Control Description: PGE is required by the conditions to the AMI order to conduct direct load control among our customers. PGE's IRP reflects 25 MW of capacity can be attained from residential customers. OPUC commissioners are particularly interested in an air conditioning pilot and water heat pilot. A critical component of direct load control for air conditioning is a programmable communicating thermostat (PCT) and control relays for water heating control. A demonstration of the cost effectiveness of direct load control on these two appliances is essential to gaining cost recovery and to expanding the program quickly enough to acquire 25 MW in two years. Equipment and installation costs for each technology are approximately $200 each. PGE is planning a small scale test of approximately 500 customers in each technology. Benefit: Approving this request will expedite the initiation of the research and results. Benefits in this specific application will be quantified against market pricing and the cost of building a peaking plant for a limited number of hours of operation. Risks of Non-Participation: PGE's timing of implementing Demand Response is subject to monitoring by the OPUC and subsequent decisions as to under whose purview DR should reside.	$100,000
EPRI Target P75.002 Mercury & Integrated Environmental Control Technology Development Description: Provides access to EPRI's evaluations of mercury capture technologies. This program is a sub-program of EPRI Target 75 which was fully funded for 2009. For 2010, we are only requesting funding for one of the three parts of Target 75 ($73,095 for P75.002). Benefit: This investigation would benefit Boardman. EPRI has also been instrumental in the development and evaluation of mercury control technologies. In 2008, EPRI co-funded the mercury testing performed at Boardman, saving PGE and its co-owners over $90,000. Risks of Non-Participation: Possible lost opportunity to significantly reduce the capital and/or operating costs for the Boardman mercury controls installation if emerging mercury control systems prove to be technically feasible and commercially available over the next year for U.S. applications.	$73,095
[1]**Geologic Sequestration of CO2 in Columbia River Group Basalts** Description: PGE has been a member of the Big Sky Carbon Sequestration Partnership since its 2004 inception. PGE's thermal power plants emit carbon dioxide (CO2). The Boardman coal plant emits around 5 million tons per year while the natural gas turbine plants emit less. To address imminent regulation of CO2 emissions in response to global climate The Partnership is one of seven federally funded, regional efforts to characterize and demonstrate the potential for CO2 sequestration especially in geologic formations. The focus of the Big Sky work has been sequestration in Columbia River Basalts. These 10,000 feet thick basalt overlay much of the Pacific Northwest. All of PGE's thermal plants sit on these basalts layers. A unique quality of basalt (a calcium, magnesium or iron silicate SiO2) is that it is very reactive with carbonic acid such as forms when CO2 is dissolved in water. Thus, if CO2 is injected into basalt not only is there the potential for pore space storage of CO2 as a gas but, when combined with pore space water, forms carbonic acid. Because of this, CO2 can then also displace the silicate yielding a "scale" or solid carbonate. In effect, the gaseous CO2 is transformed into a solid mineral, i.e., a rock. This geochemistry is well known and well demonstrated in lab and bench scales under expected injection pressure and temperature at depth.	$10,000

[1] R&D project brought forward from 2010 continuing through 2011.

Benefit: Over the past five years, Big Sky has located a test location for injection of CO2 in a supercritical liquid phase. A test well has been drilled and characterization work is nearly complete. The location is at the Boise, Inc. pulp and paper mill in Wallula, WA nearby the Port of Walla Walla. Injection of CO2 is now planned for 2nd quarter, 2010. Risk of Non-Participation: PGE would not be seen as being serious in addressing this important issue (applicable to both gas and coal fired stations).	
OSU – Carbon Balance for Capture of Flue Gas Greenhouse Gasses by Microalgae Description: PGE and Oregon State University (OSU) project: The overall goal of this study is to perform a fundamental engineering analysis on the use of algae to capture CO_2 from flue gas and process the captured carbon into lipids which can be converted into biodiesel, with specific focus on the carbon balance for the process. This information can then be used by PGE to assess the technical and economic feasibility of using algae to reduce carbon emissions from coal and gas-fired power plants. Benefit: Global climate change is an important environmental and societal issue that is being addressed in various ways including federal and state legislation limiting carbon dioxide emissions and carbon cap and trade programs. Involvement in sustainable solutions that can address multiple goals of producing biofuels while sequestering carbon dioxide will be a step towards reducing effective carbon dioxide emissions. Production of algae biodiesel utilizing flue gases from fossil fueled power plants is a sustainable renewable alternative to achieve energy security. Growing lipid-rich algae using power plant flue gases thus achieves the twin goals of providing a renewable biofuels while reducing environmental impact. Risk of Non-Participation: Investigating methods to sequester carbon dioxide will help in formulating strategies to limit carbon dioxide emissions and meet any future regulations. With imminent regulation of carbon emissions – PGE seeks to at least bound, technically and economically – any opportunity to mitigate this risk.	$5,000
[2]**Agronomy, Acceptability & Potential for Growing Giant Cane (Arundo donax) in E. Oregon** Description: It has been PGE's experience and that of its industry that fuel cycles based on biomass for power generation are defeated by unreliable production capability and or high fuel transportation costs. Transportation costs have usually been the dominant issue. PGE has become aware of and has done preliminary research on the possibility of growing Giant Cane (*Arundo donax*) near the Boardman plant as a renewable "closed loop biomass" fuel. U/W and WSU have test grown this extraordinarily productive plant in Washington's Yakima Valley for the last 6 years and have just planted 30 additional acres to test cropping and harvesting techniques. The harvested material will serve as feedstock to NW pulp/paper mills. It remains to understand whether *Arundo donax* or other 'opportunity fuel', biomass sources nearby to Boardman can either be grown or collected (or both) in sufficient quantity to be torrefied (charred) in Oregon. Once torrefied, the fuel can be stored with less concern for moisture uptake or biological degradation (e.g., mold). The ability to stockpile torrefied fuel also mitigates concerns around: • Winterkill of Arundo • Having sufficient land to produce an energy crop like Arundo • Less irrigation water due to drought or other natural events • Limited throughput of a torrefaction facility If *Arundo* proves to be the viable choice and passes muster with regard to regulatory permitting, social and agricultural acceptance and overall sustainability – PGE's initial review suggests that it can meet critical acceptance criteria as a coal substitute. Benefit: Arundo, in a torrefied form can be used to displace a portion of the coal burned at Boardman. In this	$114,000

[2] R&D project brought forward from 2010 continuing through 2011

event, it helps PGE lower its overall carbon emission footprint; adds flexibility in addressing its RPS commitment and finally can potentially lessen, if not obviate significantly, the cost of some of the capital upgrades currently envisioned for Boardman as part of the 2009 IRP. Risk of Non-Participation: Carbon emissions from burning coal exclusively at Boardman become a limiting and decisive factor. Using torrefied (charred) Arundo offers the only near term (within 5 years) of delivering a competent and cost-effective solution to the CO2 emission issue now confronting PGE's Boardman coal plant.	
Home Energy Management Description: This project with Intel and Battelle demonstrates the viability of implementing demand response utilizing equipment that can be purchased and supported via the mass-market electronics retail channel. Intel has developed a microprocessor to be embedded in video-oriented, consumer electronics (i.e. TVs, DVD players, etc.) The chip comes complete with an open-protocol, operating system. Intel's goal is to make all home-video products Internet ready. From a customer perspective, the customer sets up price and comfort preferences via the user interface on the TV. The customer does this setup one time for each appliance they add to the system. Then, an always-on portion of the Intel platform monitors prices from PGE, as required, via the Internet and sends control commands at the appropriate times to execute the customer's comfort and cost savings directives. The always-on Intel platform communicates to each appliance through WiFi or other in-home communication protocol. Benefit: Customers get the benefit of equipment sold and supported in a competitive and familiar environment. Familiarity and ease of installation will make demand response acceptable to a larger audience. Risk of Non-Participation: The Intel/Battelle model reflects the logical end state of demand response systems where innovation is driven by third parties using open platforms. In this model PGE merely provides price signals on the Internet. By not participating and proving the validity of this platform we risk much higher expenses and loss of first mover advantage in the future for equipment and maintenance of demand response equipment.	$75,000
OSU Wave Energy Research – Wave Energy Linear Generators Description: Provide support for the continued expansion of resource evaluations being used to assess renewable energy (e.g., wave, wind) potential in the Pacific Northwest. OSU's research demonstrates a compelling case for renewable energy technologies. Advanced renewable energy research may provide the benefit of encouraging new project development in Oregon. This would allow increased diversity in PGE's renewable resources portfolio. Benefit: As a result of Oregon Legislature passing a Renewable Portfolio Standard (RPS) in 2007 and in support of PGE's Integrated Resource Plan (IRP); PGE will be actively pursuing significant new renewable resources to satisfy forecast load growth ~200MWa. Today's research on advanced renewable technologies will provide important options. In order to evaluate effectively wave energy generation options, PGE must expand its knowledge base. Support of OSU's research and development of Oregon wave energy should provide significant benefit in accomplishing this goal. Risk of Non-Participation: A decision to withhold funding for the OSU wave energy program could compromise its effectiveness and the benefits it could provide, from a resource development perspective. PGE may lose the opportunity to provide input and assist in directing how this renewable resource is developed to maximize benefit to our customers	$5,000
Short-term Energy Storage Devices with Local Network Systems Description: Past PGE research began an exploration of the opportunities for local energy storage devices that could be supportive of local network systems. This effort remains focused on community scale renewable and or coupled with highly efficient community scale opportunities such as groundwater heat exchange. Benefit: As a matter of "scale matching" it is likely that limited energy storage is a much better economic application with small community energy networks than with the much, larger overall electrical grid. In some	$10,000

respects, a variation of this is being investigated now for wind power energy storage where storage supports just the peaks and valleys of wind vs. lots of wind and no wind. There is a significant difference in this approach. This project extends the thinking to small neighborhoods or communities where energy use is reasonably matched to a limited, but well stored energy supply. Risk of Non-Participation: We ignore the scale benefits of this above approach and make the potentially erroneous "one size fits all", business as usual approach to meeting small community energy needs.	
Optimizing Biglow Canyon Wind Farm Description: PGE is building the Biglow Canyon Wind Farm in three phases to provide approximately 450 MW of electric power to its customers. This development also provides a unique laboratory for many wind energy studies since the wind farm is equipped with a Supervisory Control and Data Acquisition (SCADA) system. The SCADA provides a wealth of data that can improve the project's energy output with the following objectives: 1. Determining which turbines may be underperforming for various reasons 2. Minimizing unplanned failures 3. Help in providing effective preventative maintenance 4. Determining if other turbine sites may exist in the project development area and 5. Improve energy forecasts with complimentary meteorological measurements While the data provided by the SCADA to address these areas is readily available, many times this vast amount of data is ignored or not fully used by wind farm operators. Benefit: As first priorities, PGE wishes to maximize the output from our project area and to minimize operational costs. OSU's Energy Resource Research Laboratory (ERRL) will provide optimization of the PGE Biglow Canyon Wind Farm focused, initially on using the SCADA system data to address Items #1 thru #4, above. Objectives #1 through #3 identified for maximizing project output - such as investigation of individual turbine under-performance, etc. will be the focus of the first year's work scope. These will culminate in two Tasks: • Development of testing of methodologies, and, • Data processing programs to allow wind farm operators to routinely process, in a meaningful way, the large amount of SCADA system data Risk of Non-Participation: Carbon emissions will be under increasing public scrutiny. Participating in carbon cap and trade programs will represent an additional operational expense for generating electricity from coal/natural gas. Renewable power resources such as wind farms will represent a large portion of the solution (that is also mandated by public policy); they are, however also intermittent power generating resources. The large capital expense of a wind farm must be accompanied by real efforts to maximize the output – especially in making every attempt to minimize or otherwise offset intermittency to the extent possible.	$10,000
Miscellaneous small projects awaiting PGE R&D funding approval	$8,305
PGE R&D Projects Approved for 2011	**760,000**[3]

g:\ratecase\opuc\dockets\2011 test year\testimony - pge\direct\exhibit 1000 corporate support\exhibits\exhibit 1004_rd projects_2-3-10.doc

3 For 2011, PGE is forecasting approximately $760,000 in R&D Expense, but has approved only $751,695 as of 2-16-2010.

Improvement Summary

Improvement Title: Installation of Fencing Systems at 3 Substations – TransGard Animal Fencing	Primary Contact:
	Prepared By:
	VP:
	Involved RC(s): 985, 209, 208
	Completion Date: 2007

Summarize the improvement effort

This project was submitted in 2001, an R&D project to protect animals and prevent animal caused substation outages. From 1995 – 2008 there were 67 animal caused outages. The 30 Substations now protected by TransGard Animal Fencing accounted for 44 of those outages, or 3.1 outages per year (prior to protection). Installation of the fences began in 2001 with an internal, PGE R&D grant and ran through 2007. The fencing systems have prevented animals from entering the substations. The average cost for installation was $20,000.

The repair cost of these outages ranges from a low of (minor repairs) $3,000 - $3,500 to a conservative high of $30,000 - $35,000 (can be much higher).

What are the desired end results?

- Prevent animals from entering substations and causing outages.

What result(s) from the improvement can be measured?

- Animal caused outages at protected substations.
- Repair costs per year associated with animal caused outages.
- Avoided lost revenue based on historical animal caused outage duration and frequency

Measurable Change(s)	State Before Improvement Date Measured: 1995 to 2008	State After Improvement Date Measured: 2009
Animal caused outages at protected substations	44	0
Repair cost per year (protected substations)	$60,000/yr avg.	$0
Avoided Lost Revenue (@ 9¢/kWh)	$140,000	$0

Other benefit(s)/advantage(s)

- None of these figures include money lost by customers during Substation outages. A 2004 study done by Lawrence Berkeley National Laboratory estimates that power outages and blackouts cost the U.S. about 80 billion dollars a year. It is also estimated that 98% of these costs are borne by commercial and industrial customers.
- Alternative measures to protect substation equipment averaged $40,000. TransGard averaged $20,000 per installation. For 30 substations, the cost savings would be $600,000.
- Due to the effectiveness of the Transgard fencing and the obvious avoided cost value – a report of these results has been transmitted to the OPUC as part of PGE annual Service Quality Measurement Report and to PGE's insurance brokers to negotiate favorable rates.

Table of Contents

I. Introduction

Q. Please state your names and positions.

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 appear at the end of this testimony.

My name is William J. Valach. I am the Director of Investor Relations for PGE. I am responsible for managing the relationships and communications with PGE's shareholders and the investing public. My qualifications appear 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 2011 test year. PGE's requested cost of capital and capital structure will provide PGE the opportunity to earn a fair return while keeping its costs reasonable. As Dr. Zepp discusses in his testimony (PGE Exhibit 1200), guidance regarding cost of capital decisions are provided by the Bluefield and Hope Supreme Court decisions[1] as well as ORS 756.040.

Q. What are PGE's financial goals?

A. PGE's overall goal is to be viewed in the financial markets as a well-performing, vertically integrated utility. This includes:

- Maintaining investment grade bond ratings;
- Accessing financial markets to provide liquidity for operations and capital expenditures;
- Attracting capital on reasonable terms;

[1] *Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virginia* (262 U.S. 679 (1923)) and *Federal Power Commission v. Hope Natural Gas Co.* (320 U.S. 591 (1944)).

- Achieving an actual return on equity that is at or above that achieved by a group of utilities with similar characteristics, service territory, and business risks; and
- Setting prices at a sufficient level to recover prudently incurred costs, including an overall return on utility investment.

Q. What is PGE's requested overall cost of capital for this filing?

A. We request and support an 8.289% cost of capital for the 2011 test year. This cost of capital includes a 10.50% Required Return on Equity (RROE) based on the recommendations of Dr. Zepp in PGE Exhibit 1200, with adjustments applied at the direction of PGE's CEO. These adjustments are discussed in more detail in PGE Exhibit 100. This point estimate is for revenue requirement purposes and is based on our recommended range of 8.289% to 9.039% for PGE's cost of capital and a recommended range of 10.50% to 12.00.% for PGE's RROE. 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 2011 forecasted capital structure.

Q. How did you derive the overall recommended cost of capital?

A. We first estimated the cost for the debt and equity components by considering the range, PGE's risks, and financing needs. We then determined the "weighted" cost by multiplying the component's cost by its weight (i.e., 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 summarizes these calculations.

Table 1
PGE's Weighted Cost of Capital
Test Year 2011

Component	**Average Outstanding ($000) [1]**	**Percent of Capital [2]**	**Component Cost**	**Weighted Cost**
Long-term Debt	$ 1,809,600	50.00%	6.077%	3.039%
Common Equity	$ 1,657,814	50.00%	10.500%	5.250%
Total	**$ 3,467,414**	**100.00%**		**8.289%**

[1] "Average Outstanding" reflects PGE's projected average values of long-term debt and common equity for 2011.
[2] "Percent of Capital" reflects PGE's long-term targeted capital structure of 50% debt, 50% equity, and is used to calculate PGE's weighted average cost of capital ("Weighted Cost").

Q. How is the remainder of your testimony organized?

A. In the following section, we discuss the impact of regulatory support and PGE's power cost adjustment mechanism, decoupling, and collateral costs. In Section III, we provide a review of the financial markets and economic activity. We then discuss PGE's long-term debt, including new and redeemed issues, in Section IV. In Section V, we discuss PGE's capital structure. Section VI provides our qualifications. In PGE Exhibit 1200, Dr. Zepp discusses PGE's required return on equity. He provides the analysis and support for PGE's requested RROE.

II. Regulatory Impact

Q. What impact does regulatory support have on PGE's credit quality?

A. Regulatory support to recover prudent costs is essential to maintaining a stable, investment grade credit rating. As discussed in Section V below, this support is especially important given the significant size of PGE's planned capital expenditures over the next few years.

Both Moody's and Standard & Poor's (S&P) consider regulatory support a key factor in their determination of firms' creditworthiness. Moody's places equal weighting on "Regulatory Framework" and "Ability to Recover Costs and Earn Returns" in its assessment of electric and gas utilities.[2] S&P indicates that "[r]egulation is the most critical aspect that underlies regulated integrated utilities' creditworthiness."[3] Key characteristics in the assessment of regulatory environments for both credit rating firms include the consistency and predictability of decisions, as well as the ability for timely recovery of prudently incurred costs. Good credit quality is critical to secure financing at reasonable rates and maintain access to wholesale energy markets, especially in today's volatile financial environment.

Q. You mentioned maintaining access to the financial markets as one of PGE's financial goals. Why does PGE need to maintain access to these markets?

A. PGE needs to maintain access to the equity and credit markets to provide cash and liquidity for operations, and to fund our significant capital expenditure program over the next five years, as discussed in PGE's pending 2009 Integrated Resource Plan (IRP), OPUC docket LC 48. PGE's IRP recommends significant investments in generation facilities and transmission projects, among others. In this filing, PGE has included capital expenditure

[2] "Rating Methodology – Regulated Electric and Gas Utilities." Moody's Global Infrastructure Finance.
[3] "Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry." Standard & Poor's.

forecasts of approximately $542 million in 2010, $364 million in 2011, and increasing levels in each of the following three years (see PGE Exhibit 300, Section VIII, for a discussion of capital expenditures). In 2008 and 2009, PGE's capital expenditures totaled approximately $370 million and $700 million, respectively. As noted in Section V below, a high level of capital expenditures increases the importance of supportive regulatory actions.

Additionally, 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 as we did in 2009.

Q. Have financial analysts noted any concerns regarding regulatory outcomes as they pertain to PGE?

A. Yes. Despite the fact that many credit and equity analysts have noted certain regulatory outcomes and PGE's regulatory environment as favorable aspects, they have also expressed concerns in their reports regarding PGE's Power Cost Adjustment Mechanism (PCAM) and, to a lesser degree, the decoupling mechanism adopted in the UE 197 proceeding. We address these two areas of concern, as well as PGE's proposed treatment of collateral costs below.

A. Power Cost Adjustment Mechanism

Q. What have financial analysts said about the PCAM?

A. Bank of America Merrill Lynch analysts cite concerns regarding the earnings volatility created by PGE's current PCAM. Their concerns surround the wide deadband and the asymmetry of benefits allocation, which have resulted in "meaningful" impacts on PGE's earnings. Equity analysts at Wells Fargo noted PGE's "above average earnings volatility" caused by the PCAM as a risk that justified a reduced price target. Ladenburg Thalman analysts also included PGE's "earnings volatility associated with the Power Cost Adjustment Mechanism" in formulating their rating decision.

Q. How would increased earnings volatility impact PGE's cost of capital?

A. Increased volatility results in increased uncertainty or risk. Investors and creditors require greater compensation for owning an investment with more risk, all else equal. A firm with earnings that are expected to be more volatile, thus, will have a higher cost of capital than a firm with more stable earnings. If the current PCAM structure creates 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.

Q. Will the PCAM structure changes proposed by PGE affect its cost of capital?

A. Yes. As discussed above, decreased earnings volatility will reduce PGE's cost of capital. That cost reduction will ultimately benefit customers. PGE has proposed three enhancements to the PCAM that would help reduce PGE's earnings volatility:

- <u>Symmetrical deadband</u> – PGE has proposed changing the deadband from asymmetrical to symmetrical. The symmetrical deadband would help mitigate a portion of the risk that PGE faces due to its reliance on hydroelectric power and the variable nature of this resource. As has been demonstrated by PGE in prior dockets,[4] the power cost benefits in years that hydro production is "good" (above average) are outweighed by the detrimental impacts in years that hydro production is "bad" (below average). The current asymmetric deadband, which is skewed towards PGE absorbing a larger portion of the power cost variance in years that hydro production is likely poor, negatively amplifies this already skewed distribution of hydro benefits.

- Dollar-defined deadband – PGE proposes that the deadband calculation be based on an absolute dollar range of $10.0 million, as opposed to a percentage of the authorized ROE. This modification to the current approach restricts the deadband from continually growing wider as capital additions are included in rate base and results in a more predictable and stable deadband over time given PGE's expected large capital expenditures.
- Earnings test – PGE will share a power cost variance with customers to the extent that earnings still meet the authorized ROE. In a year when the actual ROE is less than that authorized by the Commission, PGE will not be forced to forfeit earnings. This earnings test will not exacerbate under-earning or over-earning due to a power cost variance. PGE will collect any power cost variance from customers up (or refund down) to the point that actual ROE is equal to that authorized by the Commission.

[4] See for example, PGE Exhibit 301 filed in the UE 165 proceeding.

The principles of power cost adjustment mechanisms are discussed by Mr. Fetter in PGE Exhibit 1300. The above modifications to PGE's PCAM are addressed in PGE Exhibit 200 as well.

B. Decoupling

Q. Please describe PGE's current decoupling mechanism.

A. PGE proposed a decoupling mechanism in the UE 197 proceeding with the intention of removing the inherent disincentives that would otherwise exist for PGE to promote energy efficiency. Decoupling applies to residential and small commercial/industrial customer rates for a two-year trial period, as specified in OPUC Order No. 09-020. The Commission stated that, "PGE's risk will go down," and, as a result, reduced PGE's authorized ROE by 10 basis points.[5] The potential for PGE to recover an amount greater than its fixed costs under certain circumstances was taken into account in the authorized ROE reduction as well.

Q. How does the financial community view PGE's decoupling mechanism?

A. Thus far, the decoupling mechanism appears to have been viewed in a largely favorable light by the analyst community. If this view is representative of the broader financial market's view of decoupling, then it is likely that the mechanism has reduced the perceptions of PGE's risk in the market. Analysts, however, have also noted that the current decoupling mechanism leaves PGE exposed to the load fluctuations of large industrial and commercial customers, with an associated disproportionate impact on sales and revenues.

Q. What were the results of decoupling in 2009?

A. As discussed in PGE Exhibit 1500, we expect a refund to the residential customer class (Schedule 7) and a decoupling-related surcharge for small non-residential customers

[5] OPUC Order No. 09-020, pg. 28

(Schedule 32), resulting in an overall refund. This refund should be viewed in the context of the substantial load decrease experienced by PGE in 2009 relative to both the 2008 actual deliveries as well as the test year load forecast for 2009 in UE 197.

Q. Are decoupling mechanisms becoming more prevalent in electric utility regulation?

A. It appears that decoupling mechanisms are becoming more prevalent in the industry. A recent report by the Edison Foundation indicated that 19 states had decoupling mechanisms either in place or pending. In addition, seven more states had some form of lost revenue recovery mechanism in place.[6]

C. Collateral Deposits

Q. Please describe collateral deposits.

A. PGE posts or receives collateral deposits (also know as margin deposits) related to wholesale power and fuel contracts where delivery and/or settlement occur in the future. The deposits made by PGE are held by the counterparties with which PGE transacts (e.g., utilities, power marketers, and clearing brokers). These deposits are based on the difference in the contract price relative to the current market price, and in the case of deposits held by a clearing broker may also include a maintenance component.

Q. What was the collateral requirement amount included for the 2009 test year in UE 197?

A. For the 2009 test year, PGE forecasted an average balance of $10.1 million in collateral deposits.

Q. What were PGE's actual collateral requirements in 2009?

[6] "State Energy Efficiency Regulatory Frameworks." The Edison Foundation – Institute for Electric Efficiency.

A. The average month-end balance of posted collateral for 2009 was approximately $308 million. At times in 2009, however, posted collateral exceeded $425 million. These large collateral postings resulted from a significant drop in the market price for fuel and power.

Q. What are PGE's expected collateral requirements in 2011?

A. For the 2011 test year, PGE forecasts an average collateral balance of $88.9 million. This assumes no decrease in the forward market price of fuel or power relative to December 17, 2009, the date the forecast was prepared.

Q. How does PGE fund these levels of collateral requirements?

A. PGE finances collateral deposits with unsecured revolving credit facilities. Cash and letters of credit may be drawn against these facilities to fund the collateral deposits. As of December 31, 2008, PGE's total unsecured revolving credit facilities totaled $495 million. The credit facilities were increased to $600 million by December 31, 2009.

Q. How does PGE plan to fund its collateral requirements in the future?

A. We plan to increase the amount of revolving credit facilities from $600 million to $700 million, designating $500 million to meet power supply collateral requirements.

Q. What are PGE's expected costs associated with funding the collateral requirements in 2011?

A. PGE forecasts a net cost of approximately $2.6 million to fund collateral requirements in 2011. This amount represents the interest payments made on funds drawn from credit facilities and the annual cost of the facilities designated to meet power supply needs, net of the interest credited on collateral deposits. Funding collateral deposits has an expected negative carry due to the difference in the rate at which interest on the deposits is credited and PGE's costs of borrowing those funds. Interest is received only on the portion of collateral posted with cash (estimated at one-third of the balance for 2011). PGE's forecast assumes that the average annual interest rate paid to borrow cash will be 2.50%, while the interest rate received on posted collateral will be 1.50% (the forecasted Treasury Bill rate, less 50 basis points).

Q. Why do collateral and the associated costs pose a risk to PGE?

A. As market prices fluctuate, PGE may be required to significantly increase the amount of collateral posted to support its contract positions, requiring PGE to maintain sufficient liquidity to meet these collateral calls. As mentioned previously, PGE must also maintain adequate liquidity to cover the net cost of the deposits.

Q. Does the lead lag study performed by PGE account for the cost of collateral deposits?

A. No. With regards to purchased power and fuel, the lead lag study evaluates the lag between the month of delivery of power or fuel and the payment of the related invoice. It does not capture the financing costs associated with movements in the value of a power or fuel position prior to the month of delivery, which is the basis of collateral requirements.

Q. How does PGE propose to incorporate collateral costs?

A. PGE proposes to incorporate the costs associated with collateral deposits into PGE's net variable power costs for ratemaking purposes. The variability of the amount of outstanding collateral deposits is directly tied to PGE's power supply positions and is, therefore, directly aligned with the Annual Update Tariff (AUT) filing and subsequent Power Cost Adjustment Mechanism true-up. Collateral costs are also addressed in PGE Exhibit 400.

III. Financial Market and Economic Overview

Q. Please provide an overview of the financial market conditions that existed during 2009.

A. Equity and credit markets were both marked by periods of extreme volatility in 2008 and 2009 as the economic downturn, or "Great Recession," wore on. A partial list of factors that may have contributed to the equity and credit market conditions include: the housing/mortgage crisis in the U.S. and other developed countries, the increased perceptions of counterparty risk globally following the failure of Lehman Brothers and subsequent "bailout" of other financial firms, a severe lack of liquidity in some market sectors, and the implications of a protracted global recession.

The sell-off in equities began accelerating late in the third quarter of 2008 and drove the S&P 500 index down to mid-1990s levels. At its nadir in March 2009, the index had fallen 25% from the first of the year and more than 50% relative to its historical peak in October 2007. From March, the index rallied nearly 65% by year-end 2009, but was still approximately 30% below its October 2007 peak.[7]

Q. You mentioned that the equity markets are more volatile than in the past. Does a readily available indicator or measure of volatility in the U.S. equity market exist?

A. Yes. The Chicago Board Options Exchange (CBOE) Volatility Index (VIX) measures option investors' consensus views of future expected stock market (as represented by the S&P 500 Index) volatility. The index measures the 30-day volatility implied by the prices of near-term and next-term S&P 500 Index options (in other words, the nearest two months' option contracts that have at least one week until expiration).[8] The VIX is often referred to

[7] Index data retrieved from http://www.snl.com
[8] "The CBOE Volatility Index – VIX." http://www.cboe.com/micro/vix/vixwhite.pdf

as the “fear index” or “investor fear gauge” because expected volatility tends to rise in periods of market turmoil.

Q. Based on the VIX, has volatility increased in the equity markets?

A. Yes. In the midst of the market panic in the fourth-quarter of 2008, the VIX breached 80; a level more than four-times its daily average close for the preceding 19 years. Prior to this massive financial turmoil, the high closing mark for the index was just over 45, a point reached only three times in its history: twice in 1998 and once in 2002. During the current financial crisis, the index closed above 45 a total of 83 days between September 2008 and the end of March 2009, as can be seen in the chart above, which is also provided as PGE

Exhibit 1102.[9] This is indicative of the heightened levels of investor concern and volatility present in the equity markets during portions of 2008 and 2009.

In the year preceding each of PGE's two previous general rate case filings (UE 180 and UE 197, filed in 2006 and 2008), the index average was approximately 15, much lower than its current level, and much lower than the average of 31 in 2009. Although these are historical, not forward-looking, volatility figures, as noted by Dr. Zepp in his testimony, investors are "still wary about what that future will bring" given this recent market environment.

Q. Was the "volatility" and "turmoil" limited to the equity markets?

A. No. Extremely tough conditions existed in the credit markets as well during the period, which we address in Section IV below.

Q. Has the economy in the United States recovered?

A. No. The timing and extent of any general economic recovery remains a highly debated topic. The statement released on December 16, 2009 by the Federal Reserve following the Federal Open Market Committee (FOMC) meeting suggests that while economic conditions in the United States are improving, significant risks remain. The FOMC noted that although it is likely to remain weak for some time, economic activity in the country had "continued to pick up" since its prior meeting. Also, when discussing their outlook on December 8, 2009 for the U.S. economy in 2010, Standard & Poor's economists opined that, "although most of the bad things have stopped happening, there are few good things boosting growth."[10]

[9] Index data retrieved from http://www.cboe.com/micro/VIX/historical.aspx
[10] "U.S. Economic Forecast: An Imperfect '10." Standard & Poor's.

Q. Does the FOMC statement mention any risks or specific areas of concern in the economy?

A. Yes. The December FOMC statement mentions factors such as the weak labor market, tight credit availability, and the decrease in business fixed investment that continue to weigh on the economy.[11] The unemployment rate in the country (as reported by the Bureau of Labor Statistics) was 10.0% in December 2009, which is down slightly from October 2009.[12] Goldman Sachs forecasts the unemployment rate in the U.S. to remain "near or above 10% through 2010."[13] Generally dependent upon the rate of economic growth, the timing and extent of improvement in the nation's unemployment rate is, thus, uncertain as well.

Q. Do other potential risks remain in the U.S. or global economy?

A. Yes. S&P notes that non-residential construction remains the "major negative left" in the U.S. economy and is not likely to recover until 2011.[14] Others note that commercial real estate represents a major risk, as does the growing U.S. deficit.[15] According to a report in the Wall Street Journal, delinquency rates on commercial mortgages reached 6.07% in December 2009. This marks the highest recorded delinquency rate since the commercial mortgage-backed security market began.[16]

Non-U.S. entities with credit problems continue to make headlines as of December 2009. Dubai World (a corporation run by the emirate) announced on November 26th that it was seeking to delay payments on a portion of its $59 billion of outstanding debt. Markets were initially shaken by the news, but recovered when it was revealed that less than half of

[11] https://www.federalreserve.gov/newsevents/press/monetary/20091216a.htm
[12] Data retrieved from http://www.bls.gov/
[13] "United States: Utilities: Power – Electric Utilities." Goldman Sachs Global Investment Research
[14] "U.S. Economic Forecast: An Imperfect '10." Standard & Poor's.
[15] "Crisis in sovereign, commercial debt seen." http://www.reuters.com/article/idUSTRE5B64B920091207
[16] "Commercial Mortgage Delinquencies Spike, But There Is Hope." http://online.wsj.com/article/BT-CO-20100107-710296.html?mod=dist_smartbrief

the outstanding debt needed to be restructured.[17] On December 16, 2009, the credit rating for Greece was cut by S&P as a result of the country's current debt load, which was reported to be 12.7% of GDP, and the failure of an announced reform plan to adequately address the steps to reduce the debt level. This move came a week after Fitch also downgraded the country's debt.[18]

Q. With all of the conditions discussed above, was PGE still able to maintain access to the financial markets during 2009?

A. Yes. As we discuss in Section IV below, PGE was able to issue $580 million of debt during 2009. PGE's solid, investment grade credit ratings and positive credit quality allowed PGE continued access to credit markets. Additionally, PGE issued 12.5 million shares of common stock, raising $176 million, in March 2009, albeit at a price substantially below book value.

Q. What is the impact on existing shareholders of issuing equity at a price that is below the firm's book value per share?

A. The price at which new shares are issued is dependent upon the maximum price that the market will bear at that time. A firm that is faced with issuing shares at a price that is less than the book value per share dilutes the stakes of existing shareholders. The new stockholders are essentially paying less for their ownership share, or contributing less equity per share to the company, than the value of the existing shareholders' stake that is reflected on the balance sheet. Any claim to earnings, however, is still shared equally by the owners. Following the announcement of PGE's equity issuance in March 2009, Shields & Company

[17] "Limited Risk to Euro-Area Banks Seen From Dubai Debt." http://www.bloomberg.com/apps/news?pid=20601085&sid=atEJ7E_SUTb8
[18] "Greece attacks S&P over downgrade." http://www.ft.com/cms/s/0/d4bdc8f2-eb13-11de-a0e1-00144feab49a,dwp_uuid=2b8f1fea-e570-11de-81b4-00144feab49a.html

published a report describing the decision to issue equity below book value as one of the rules that should never be violated by a utility, but one that was nonetheless necessitated by capital expenditures and potential concerns related to credit rating metrics.[19] Diluting existing shareholders with an equity issuance priced below book value is clearly not a preferred or sustainable method of securing financing, especially for a firm that needs to continue raising funds in the equity market in the future.

[19] "POR to Issue Equity Below Book Value." Shields & Company. March 5, 2009.

IV. Cost of Long-Term Debt

Q. How did you calculate the cost of long-term debt for 2011?

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 issues as of December 31, 2009, as well as bond issuances and retirements expected in 2010 and 2011. 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 issue. The effective interest rate represents the internal rate of return for each of the cash flows associated with each debt issue, including all unamortized call premiums and issuance expenses for debt issues replaced before maturity with less expensive financings. PGE's annual cost of long-term debt for the 2011 test year has decreased from that authorized in UE 197 by 49 basis points, a significant decline. Table 2 below summarizes PGE's cost of long-term debt for 2011.

Table 2
PGE's Cost of Long-Term Debt ($000)

	2011	UE 197 (2009)	Difference
Principal Amount	$ 1,809,600	$ 1,613,950	$ 195,650
Annual Interest Cost	$ 109,969	$ 105,988	$ 3,981
Effective Interest Rate	**6.077%**	**6.567%**	**-0.490%**

A. Credit Market Conditions

Q. How have the credit markets changed since PGE filed its last general rate case in early 2008?

A. As we noted above, markets were very turbulent in 2008. Credit markets regained some semblance of normalcy by the end of 2009; however, a great deal of turmoil existed throughout the year. A combination of 'flight-to-quality' and government intervention sent Treasury yields to historic lows. The lowest market yields in history for Treasury securities all occurred in the period from mid-December 2008 through December 2009 (based on daily reported market yields).[20]

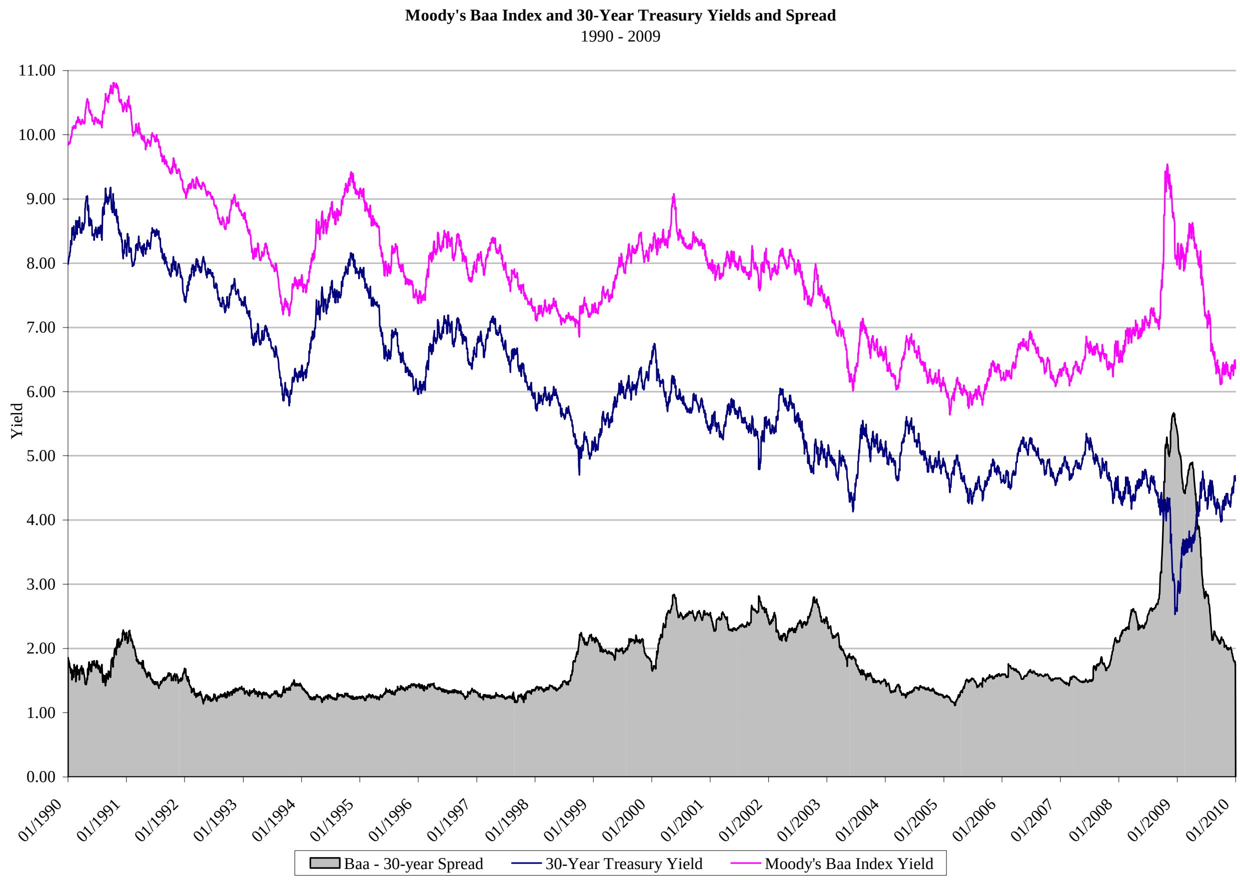
The low yields on Treasury securities and the low Federal Funds rate would seem to indicate low borrowing costs. Additional factors, however, are at play in the determination of market interest rates such as the spread applied to the Treasury rate. This spread, or difference in yield, is typically referred to as a "credit spread" that compensates the lender for credit quality differences from U.S. Treasuries. The total spread may also include an amount to compensate for illiquidity as well.

Q. What impact did this 'flight-to-quality' have on market interest rates?

A. 'Flight-to-quality' drove Treasury yields down, but also had the effect of widening the credit spreads. For the most part, spreads peaked in December 2008 during the fallout from the Lehman Brothers bankruptcy and the AIG (among others) bailout. At that point, the spread between the yield on the Moody's Seasoned Corporate Bond Baa index and the 30-year U.S. Treasury Bond constant maturity index was more than 560 basis points (bps). Over the course of the nearly 17.5 years prior to the onset of the credit crisis, the spread had averaged approximately 167 bps. By mid-June 2009, the spread was back under 300 bps and, as of

[20] Data retrieved from https://www.federalreserve.gov/datadownload/

December 31, 2009, had declined to less than 200 bps.[21] This relationship is detailed in the graph below, which is also provided as PGE Exhibit 1103.



Increased spreads mean that a borrower will pay more in interest to its creditors for the ability to borrow the funds.

Q. Given these widened spreads, did PGE pay more for its debt issuances in 2009 than it has historically?

A. Fortunately, no. Regulated utilities tended to be viewed more favorably in the markets during this period than other corporate borrowers, and, thus, were not subject to the full

[21] Ibid.

extent of the widened spreads.[22] The timing of issuances was important as well, as indicated by the decline in spreads by June 2009. PGE was able to take advantage of this environment and reduce its cost of debt since the last general rate case filing in UE 197.

Q. Have PGE's credit ratings changed since UE 197 was filed in 2008?

A. Yes. On January 29, 2010, PGE's corporate credit rating was reduced from 'BBB+' to 'BBB' with a 'Stable' outlook by Standard & Poor's.[23] At the same time, S&P reduced PGE's Senior Secured rating one notch from 'A' to 'A-'. PGE's issuer rating with Moody's remains unchanged at 'Baa2'.[24] PGE's credit ratings are provided in PGE Exhibit 1104.

B. Debt Issuances and Redemptions

Q. What future debt issuances did you include in your analysis?

A. We expect to issue $180 million in debt during the remainder of 2010. Approximately $121 million of this amount will be in the form of two pollution control bond (PCB) issues that PGE plans to remarket. As discussed below, these bonds were put-back to PGE by investors in 2009. The remaining $59 million, along with the expected interest rate and issuance cost, has been incorporated into PGE's cost of long-term debt presented in PGE Exhibit 1101. PGE does not expect to issue long-term debt in 2011.

Q. What is the expected term, coupon rate, and issuance cost for the bonds still to be issued in 2010?

A. PGE currently expects the two PCB issues representing $23.6 million and $97.8 million to be remarketed for the remainder of their 23-year terms with coupon rates of 5.0% and 5.1%.

---

[22] "U.S. Utility And Power Sector Refinancing Requirements Remain Manageable For The Next Few Years." Standard & Poor's.
[23] "Research Update: S&PCORRECT: Portland General Electric Co. Corporate Credit Rating Lowered To 'BBB' On Weak Economy." January 29, 2010. Standard & Poor's.
[24] "Credit Opinion: Portland General Electric Company." September 24, 2009. Moody's Investors Service.

The $59 million bond issuance is expected to carry a coupon rate of approximately 4% for a term of 7 years. The actual rates and terms are subject to change based on prevailing market conditions as PGE seeks the lowest cost financing option at the time of issuance. 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 issue pricing analysis provided by an investment banking firm, and PGE's expectations and prior experiences when issuing debt.

Q. Is any long-term debt maturing in 2010 or 2011?

A. Yes. Three issues are maturing in 2010, representing approximately $186 million. Two Trojan PCB issues with face amounts totaling $36.90 million, originally issued in 1985 for terms of 25 years, are maturing in April and June 2010. In addition, an unsecured note with $149.25 million of principal outstanding originally issued in 2000 for a term of 10 years is maturing in March 2010. There are no long-term debt issues maturing in 2011.

Q. Has PGE issued or redeemed any long-term debt since PGE filed UE 197 in 2008?

A. Yes. In UE 197, PGE expected to issue $250 million for 30 years at 6.890% in 2009 but instead issued a total of $580 million for terms ranging from 5 to 30 years at rates between 5.430% and 6.800%. $70 million was issued for a term of 5 years at a 3.460% rate in January 2010. These debt issuances are detailed in PGE Exhibit 1101.

Much of this additional financing activity occurred because in UE 197, PGE expected to remarket three PCB issues totaling $142.4 million during 2009. These three PCB issues were contractually put-back, or returned, to PGE in May 2009, at which point PGE decided to hold them because market conditions were unfavorable. The interest received by an investor from holding pollution control bonds is tax-exempt, and, thus, the PCBs should theoretically carry coupon rates and trade at yields that are less than their taxable equivalents. Due to certain concerns and stress in the credit markets during 2009, however, yields on pollution control bonds were at times actually higher than taxable bonds of an equivalent term. Given these market conditions, PGE chose not to remarket the PCBs, but rather to use taxable first mortgage bonds (FMBs).

Conditions in the credit markets in the first quarter of 2010 have made some PCBs a cost-effective financing option once again. As discussed above, PGE plans to remarket two of these three issues for $121.4 million in the first quarter of 2010. PGE retains the ability to remarket the remaining PCB issue at a later date if market conditions improve and remarketing becomes cost effective.

Q. How did PGE incorporate the unamortized issuance costs related to the PCBs into the cost of debt calculation?

A. For the two PCB issues that PGE plans to remarket, the remaining issuance costs from the prior remarketing have been incorporated as unamortized issuance costs and will be amortized over the 23-year life of the bonds. For the one PCB issue that PGE does not plan to remarket at this time, the issuance costs that remained unamortized at the time the issue was put-back to PGE were assumed to be amortized on a straight-line basis over the course of the remaining life of the bond and included as a loss on reacquired debt.

Q. What impact did PGE's decision to seek alternative forms of financing vis-à-vis remarketing the PCBs have on customers?

A. PGE's decision to issue FMBs rather than remarket the PCBs resulted in a lower cost of debt. This lower cost of debt means that PGE will spend less annually in interest payments, resulting in lower costs for customers.

Q. Since UE 197, what impact have PGE's overall financing activities had on customers?

A. At the 2011 outstanding effective interest rate, PGE will incur almost $9 million less in interest and related charges (issuance costs and charges related to the amortization of losses on reacquired debt) than if the same debt balance was outstanding at the UE 197 effective interest rate.[25] PGE has been able to secure nearly $196 million in additional financing while incurring roughly $4 million in additional annual interest and related charges.

---

[25] (6.567% - 6.077%) x $1.8096 billion

V. Capital Structure

Q. How did you determine the appropriate level of common equity for 2011?

A. We evaluated PGE's capital structure using the forecasted income statement and balance sheet for 2011, as well as our expected financings through 2011. 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 180 (Order No. 07-015) and UE 197 (Order No. 09-020).

Q. Does PGE expect to issue equity in 2011?

A. PGE's decision to issue common equity in 2011 will be dependent upon planned capital expenditures. As mentioned above, PGE's pending IRP illustrates a significant capital expenditure program. Those projects and their costs, however, are subject to change. As the projects change, PGE's financing needs will change as well, which will impact the amount and timing of any equity issuance. Assumptions regarding future financing needs will be updated as more current information becomes available during the course of this proceeding.

Q. Are you seeking a different capital structure than that in UE 197?

A. No. In UE 180, Order No. 07-015 set PGE's regulated capital structure at 50% equity and 50% debt. The stipulation reached in UE 197, Order No. 09-020, reaffirmed this regulated capital structure. PGE's long-term goal continues to be to maintain our capital structure at 50% equity and 50% debt; however, the equity ratio does fluctuate around the 50% target level, due to the timing and size of debt and equity issuances. PGE expects the level of regulated equity to exceed 50% by the end of the test year, but we continue to recommend a 50% equity and 50% debt capital structure.

Q. Why does PGE intend to maintain a 50% equity, 50% debt capital structure?

A. The equity portion of PGE's capital structure is important to 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 offset the leverage imputed by the rating agencies due to its above-average reliance on purchased power. Additionally, PGE faces many risks in today's environment and it must be able to maintain a solid capital structure and financial flexibility in order to help contain customer costs and retain shareholder value.

Q. Has the Commission noted any specific risks facing PGE?

A. Yes. In UE 180, Order No. 07-015, the Commission noted that PGE has significant exposure to the wholesale market, especially when compared with PacifiCorp. In particular, PGE faces risk related to the volatility of wholesale electricity prices. Volatility in these markets can affect the availability and the prices of purchased power and demand for energy sales. This volatility can result in the deterioration of market liquidity, increase counterparty credit risk, and impair PGE's ability to manage its energy portfolio. While PGE's power cost adjustment mechanism (PCAM) mitigates this risk to some degree, it does not provide full recovery of all costs outside the cost sharing features. In Order No. 07-015, the Commission found that an additional 10 basis points on ROE was appropriate to balance PGE's risk exposure in this area.

Q. Aside from the risks discussed above, what other types of risks does PGE encounter today?

A. PGE faces a multitude of other risks and uncertainties, including:

- Imputed debt from purchased power contracts: Some rating agencies impute debt on PGE's purchased power contracts and operating leases. This has an indirect impact on PGE's credit rating. Based on third quarter 2009 financial information, Standard & Poor's method for calculating the imputed debt of these contracts added approximately 2.2% of additional debt to PGE's capital structure.
- SB 408 and related earnings volatility: Oregon law SB 408 adjusts the way that PGE and other Oregon investor-owned utilities recover income tax expense from customers. SB 408 has financial impacts on PGE, especially earnings volatility. As discussed above with regard to PGE's Power Cost Adjustment Mechanism, earnings volatility increases risks for PGE and its investors, requiring a higher return than otherwise.
- Large capital program over the next five years: PGE has begun a large capital expenditure program that will continue for at least the next five years if the projects set forth in PGE's pending 2009 Integrated Resource Plan are pursued. As discussed in Section II above, access to the capital markets is critical to fund these expenditures. In the financial markets, PGE has the risk of experiencing higher than expected costs or a lack of market liquidity to fund its capital program. A strong balance sheet and a higher return on equity reflective of this risk is necessary to remain a marketable company in these volatile financial markets.

Regulatory support to recover these investments is a crucial consideration in maintaining PGE's access to credit as well. Moody's credit rating methodology notes that, "[t]he ability to recover prudently incurred costs in a timely manner is perhaps the single most important credit consideration for regulated utilities." The methodology, dated August 2009, goes on to state that, "the utility industry's sizable capital expenditure requirements for infrastructure needs will create a growing and ongoing need for rate relief of recovery of these expenditures at a time when the global economy has slowed."[26]

- Hydro and wind availability and weather volatility: Weather conditions can adversely affect PGE's revenues and costs. Weather creates risk for PGE in several ways, including:
    - Lower than average stream flows;
    - Lower than average wind flows; and
    - Volatility in electricity usage because of sudden, unexpected, weather changes.

  All of the above can potentially force PGE to purchase more spot energy, when the markets may be tight. The higher costs resulting from these purchases combined with the volatility of weather conditions can increase costs to PGE and its investors, requiring a higher return than otherwise.

- Regional economic weakness: Regional economic weakness can adversely affect PGE's revenues. Weakness in the regional economy, and thus 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.

[26] "Rating Methodology – Regulated Electric and Gas Utilities." Moody's Global Infrastructure Finance.

Oregon's economy was especially hard-hit during the recession that began in 2007. Unemployment in the state may have peaked in May 2009 at a rate of 12.2%. The preliminary estimate for the state of Oregon unemployment rate in December 2009 (the most recent month for which data is available) was 11.0%, still exceedingly high. As discussed above, the national unemployment rate in December 2009 was 10.0%.[27]

- Renewable Portfolio Standard (RPS) compliance risk: Oregon's RPS requires that PGE serve at least 25% of its retail load from renewable resources by the year 2025, with interim requirements in years 2011, 2015 and 2020. PGE faces the risk that lower cost renewables will be acquired by other utilities or will be unavailable in a timely manner. In addition, PGE will incur other potential risks when placing these resources into rate base, including regulatory risk, transmission congestion, resource availability, etc. PGE faces further potential risks when seeking to efficiently integrate certain of these renewable resources into its energy portfolio.
- Uncertainty regarding an adverse Trojan decision: There is uncertainty in the financial markets regarding the ultimate outcome of the legal proceedings related to PGE's recovery of its investment in the Trojan Nuclear Plant. This risk is discussed by several financial analysts in their publications. In Standard and Poor's February 2009 and August 2009 reviews of PGE, the uncertainties associated with Trojan, including the difficulty of quantifying the potential exposure and estimating the timing of a final outcome, were listed as weaknesses.

[27] Data retrieved from http://www.bls.gov/

Standard & Poor's noted that an adverse outcome could have a negative impact on PGE's credit rating.

- Uncertain federal energy policy: The federal government's potential policies regarding renewable energy mandates and the potential for restrictions on carbon emissions remain unclear. Passage of the American Clean Energy and Security Act (also know as the Waxman-Markey bill) in the U.S. House of Representatives is perhaps the first step in a move to pass legislation aimed at managing carbon emissions in the United States. The ultimate form of any policy, and the impacts on regulated utilities, cannot be known at this point.

Q. Do the financial markets agree that these are risks for PGE?

A. Yes. Recent reports from Standard & Poor's, Moody's, and various equity analysts include at least one of the risks listed above.

Q. How does PGE manage these risks?

A. PGE can manage some of these risks, but others it cannot. Risks PGE cannot manage include those associated with the government or regulatory framework, such as SB 408. For many risks, even though PGE can partially manage them, PGE remains significantly exposed.

Q. In total, how do the risks addressed above impact the cost of capital you request?

A. PGE is subject to a variety of risks that must be considered in the determination of an appropriate overall cost of capital. If those risks are not mitigated to the point that PGE is comparable to its peers, the cost of long-term debt and the cost of equity will increase, with a resulting long term cost impact on customers.

VI. Qualifications

Q. Mr. Hager, please state your educational background and experience.

A. I received a Bachelor of Science degree in Economics from Santa Clara University in 1975 and a Master of Arts degree in Economics from the University of California at Davis in 1978. In 1995, I passed the examination for the Certified Rate of Return Analyst (CRRA). In 2000, I obtained the Chartered Financial Analyst (CFA) designation.

I have taught several introductory and intermediate classes in economics at the University of California at Davis and at California State University Sacramento. In addition, I taught intermediate finance classes at Portland State University. Between 1996 and 2004, I served on the Board of Directors for the Society of Utility and Regulatory Financial Analysts.

I have been employed at PGE since 1984, beginning as a business analyst. I have worked in a variety of positions at PGE since 1984, including power supply. My current position is Manager, Regulatory Affairs.

Q. Mr. Valach, please state your educational background and experience.

A. I received a Bachelor of Science degree in Business Administration from the University of Montana in 1979. I received a Masters in Business Administration from the University of Oregon in 1986 with an emphasis in Finance. I joined PGE in 1991 as a Business Analyst and was Manager of Corporate Finance and Assistant Treasurer from July 1997 to September 2005 and from August 1, 2009 to February 4, 2010. Since Fall of 2005, I have also held the title of Director of Investor Relations.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit 1101
Cost of Long-Term Debt Estimate
December 31, 2011

(A)	Ledger (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	G11501	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	1.105%	0.104%
2	G21195	PCB	Trojan 90A Fixed	1-Jul-98	1-Aug-14	16	5.250%	$9,600,000	$103,771	$184,980	*1*	$9,311,249	5.537%	96.992%	$9,600,000	$9,311,249	0.531%	0.029%
3	G11514	FMB	5.6675% Series	28-Oct-02	25-Oct-12	10	5.245%	$100,000,000	$11,305,461	$0		$88,694,539	6.823%	88.695%	$100,000,000	$88,694,539	5.526%	0.377%
4	G11516	Series VI MTN	5.625% Series	4-Aug-03	1-Aug-13	10	5.398%	$50,000,000	$408,842	$1,946,809	*2*	$47,644,349	6.032%	95.289%	$50,000,000	$47,644,349	2.763%	0.167%
5	G11517	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	2.763%	0.193%
6	G11518	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	2.763%	0.195%
7	G11521	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	9.671%	0.642%
8	G11519	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	5.526%	0.368%
9	G11522	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	9.394%	0.551%
10	G11523	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	7.184%	0.424%
11	G11524	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	4.145%	0.245%
12	G11525	FMB	4.450% Series	15-Apr-08	1-Apr-13	5	4.450%	$50,000,000	$915,100	$1,990,993	*5*	$47,093,907	5.806%	94.188%	$50,000,000	$47,093,907	2.763%	0.160%
13	G11526	FMB	6.500% Series	15-Jan-09	15-Jan-14	5	6.500%	$63,000,000	$412,020	$0		$62,587,980	6.656%	99.346%	$63,000,000	$62,587,980	3.481%	0.232%
14	G11526	FMB	6.800% Series	15-Jan-09	15-Jan-16	7	6.800%	$67,000,000	$438,180	$0		$66,561,820	6.919%	99.346%	$67,000,000	$66,561,820	3.702%	0.256%
15	G11527	FMB	6.100% Series	13-Apr-09	15-Apr-19	10	6.100%	$300,000,000	$2,386,223	$0		$297,613,777	6.208%	99.205%	$300,000,000	$297,613,777	16.578%	1.029%
16	G11528	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	8.289%	0.454%
17	G11529	FMB	3.460% Series	15-Jan-10	15-Jan-15	5	3.460%	$70,000,000	$550,000	$0		$69,450,000	3.633%	99.214%	$70,000,000	$69,450,000	3.868%	0.141%
18	N/A	PCB	Clstrp 98A Fixed	4-Mar-10	1-May-33	23	5.100%	$97,800,000	$860,640	$1,523,172	*6*	$95,416,188	5.283%	97.563%	$97,800,000	$95,416,188	5.405%	0.286%
19	N/A	PCB	Brdmn 98A Fixed	4-Mar-10	1-May-33	23	5.000%	$23,600,000	$207,680	$912,821	*6*	$22,479,499	5.360%	95.252%	$23,600,000	$22,479,499	1.304%	0.070%
20	N/A	FMB	4.000% Series	15-Jul-10	15-Jul-17	7	4.000%	$58,600,000	$439,500	$0		$58,160,500	4.124%	99.250%	$58,600,000	$58,160,500	3.238%	0.134%
			Annual expense from loss on reacquired debt							$391,732		($391,732)						
			Totals					$1,809,600,000	$25,987,694	$21,227,548		$1,762,384,758			$1,809,600,000	$1,762,776,490	100.00%	6.055%
			Cost of LT Debt (includes annual expense from loss on reacquired debt)															**6.077%**

	Losses on Reacquired Debt	Issue Date	Reacquisition Date	Gross Proceeds	Total Gain/Loss to Amortize	Annual Expense
Y61181	13.50% FMB Due 10/1/12	19-Oct-82	25-Apr-88	$75,000,000	$8,989,952	$374,581
G21184	5.450% Colstrip 98B Fixed PCB due 04/30/33	1-May-03	1-May-09	$21,000,000	$411,622	$17,151
						$391,732

Footnote

1 On 7/1/98, the Trojan variable rates were fixed, although not extended.

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).

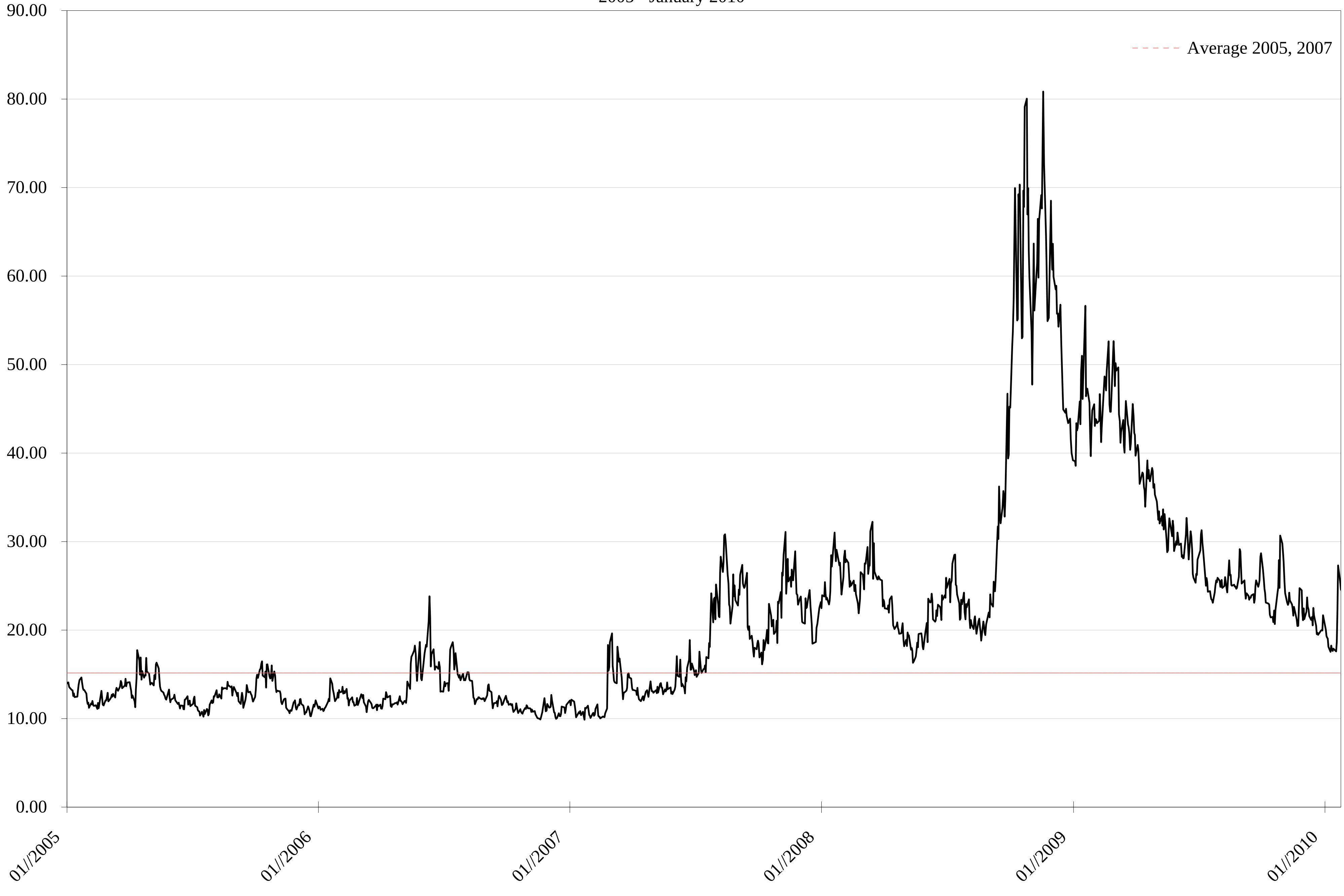
3 There was a $12 million call premium on the 8.125% redeemed issue. A portion was disallowed in UE 180. The remainder is rolled into the new debt and will be paid over the period of the May 2006 issuances.

4 $5.1 million Trojan 1990B PCBs redeemed early in June 2007. Unamortized loss of $50,969 was added to the 5.80% series $170MM issued in May 2007 used to redeem the PCBs.

5 In February 2008, PGE repurchased the 5.279% issue due 04/01/2013. The issue was subsequentally reissued on 04/15/2008 at 4.45% for a period of 5 years (due on original maturity date of 04/01/2013).

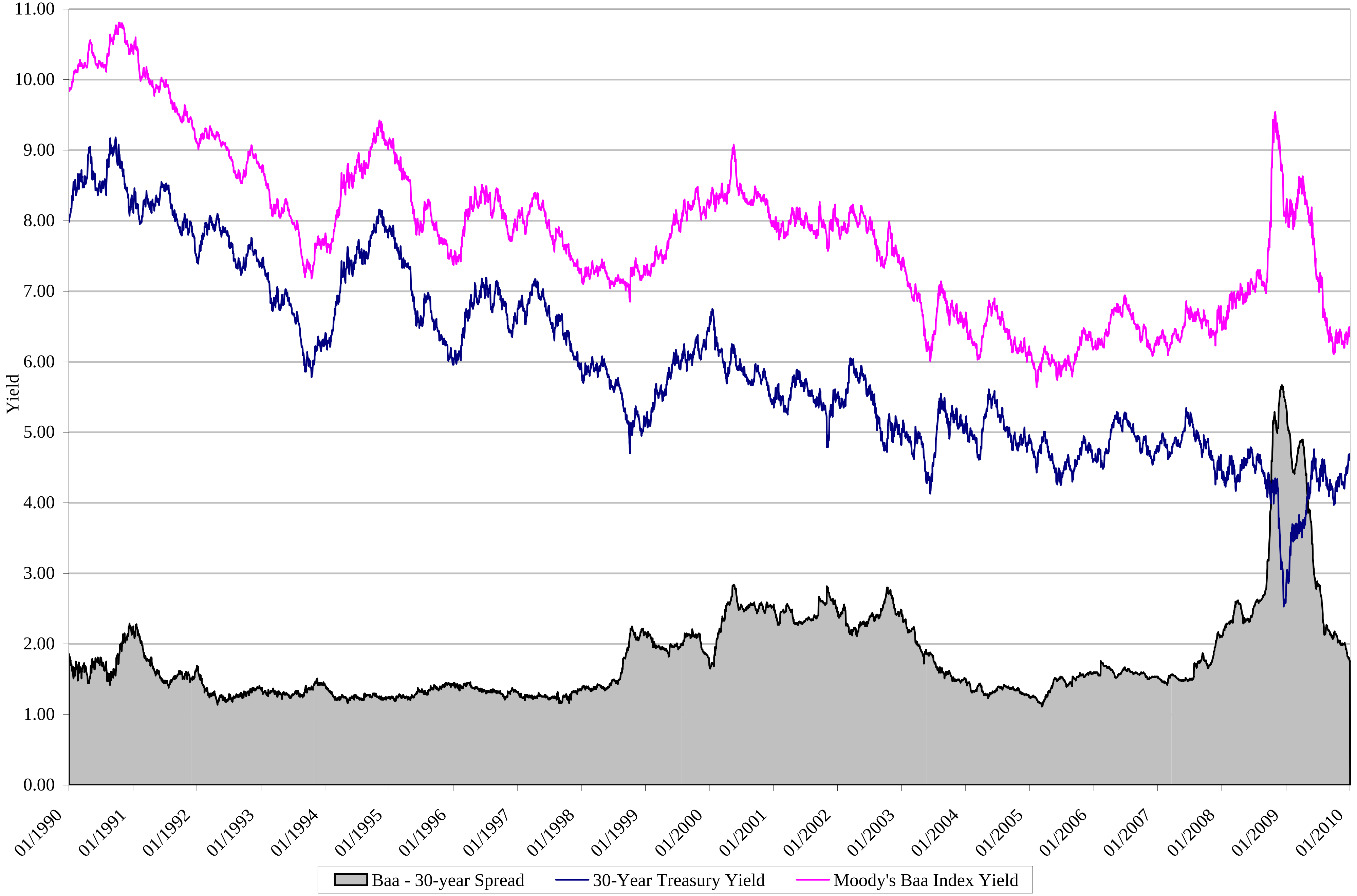
6 PCB issues put-back to PGE in May 2009. PGE plans to re-market in March 2010 (due on original maturity date of 05/01/2033).

PGE Exhibit 1102
VIX Index Daily Close
2005 - January 2010



Source: http://www.cboe.com/micro/VIX/historical.aspx

PGE Exhibit 1103
Moody's Baa Index and 30-Year Treasury Yields and Spread
1990 - 2009



Source: https://www.federalreserve.gov/datadownload

PGE Exhibit 1104
Standard & Poor's and Moody's Investors Service Credit Ratings

	S&P	Rating Date	Moody's	Rating Date
Long-term Issuer	BBB	1/29/2010	Baa2	9/24/2009
Senior Secured Debt	A-	1/29/2010	A3	9/24/2009
Senior Unsecured	BBB	1/29/2010	Baa2	9/24/2009
Short-term/Commercial Paper	A-2	1/29/2010	P-2	9/24/2009

http://www.snl.com
“Research Update: S&PCORRECT: Portland General Electric Co. Corporate Credit Rating Lowered To 'BBB' On Weak Economy.” January 29, 2010. Standard & Poor’s.
“Credit Opinion: Portland General Electric Company.” September 24, 2009. Moody’s Investors Service.

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 vice president of Utility Resources, Inc., Suite 250, 1500 Liberty Street, S.E., Salem, Oregon 97302. My qualifications appear at the end of this testimony.

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 early December 2009.

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 PGE
First Discounted Cash Flow ("DCF") Analysis	11.7%
Second DCF Analysis	11.7%
Third DCF Analysis	11.4%
First Risk Premium ("RP") Analysis	11.1% to 11.5%
Second RP Analysis	10.9% to 12.0%
Third RP Analysis	11.1%
Comparable Earned and Authorized ROEs	11.0% and 11.0%
Estimated Range of Equity Costs	10.9% to 12.0%

Each of these estimates of PGE's RROE includes a 20 basis point risk adjustment to reflect that PGE is more risky than the sample I use to determine the benchmark cost of equity estimates. I recommend that PGE be authorized an ROE of no less than 11.0%.

Q. Will PGE require a higher ROE in 2011 than it required when you prepared testimony in late 2007?

A. Yes. Since the time I prepared direct testimony for PGE in UE 197, the seriousness of the financial crisis has been recognized and there has been an unusually severe recession. During the last two years, there has been a "flight to quality" as investors have sold risky assets and bought Treasury securities. As the demand for Treasury securities increased, prices for the Treasury securities increased, Treasury rates declined and the expected spread between Baa Corporate bond rates and 30-year Treasury rates increased. See PGE Exhibit 1202. In most periods, costs of common equity tend to move in the same direction as Treasury rates but by less. In the current situation, however, evidence indicates costs of equity have increased even though Treasury rates have declined. Annual average Treasury rates forecasted for the period when PGE's new rates will be in effect are lower than in the period 1990 to 2008 (see PGE Exhibit 1202). Spreads between Baa bond rates and Treasuries are forecasted to stay higher during the period new PGE rates will be in effect than in the period 1990 to 2008 (compare PGE Exhibit 1202 and PGE Exhibit 1211).

Also, even though Treasury rates are now lower than forecasted Treasury rates at the time I prepared testimony in 2007 (compare UE 197/PGE Exhibit 1011 Zepp to PGE Exhibit 1211), DCF equity cost estimates using similar models are higher today than in 2007 when I prepared equity cost testimony for PGE (Compare UE 197/ PGE Exhibit 1016 Zepp to PGE Exhibit 1216). In UE 197, DCF estimates of the cost of equity for a benchmark sample of electric utilities fell in a range of 10.5% to 11.3%. Currently, updates of those DCF models indicate the cost of equity for the benchmark sample falls in a range of 10.7% to 11.8%.

As a result, even though Treasury rates have declined, three versions of the DCF model indicate the cost of equity for PGE in 2011 has increased. Once complete estimates of the RP and DCF models are made, I find PGE's expected cost of equity in 2011 falls in a range of 10.9% to 12.0%. A comparable range was 10.7% to 11.5% in November 2007.

Q. Please discuss recent developments in financial markets that put your current equity cost estimates in perspective.

A. My equity cost estimates are forward-looking, but investors have been beaten up badly in the last two years and are still wary about what that future will bring. While it now appears that the economy is slowly pulling out of recession and may well have been out of recession for a while, there is still talk of a possible "double dip" recession in which the economy falls back into recession before a full recovery from the last one is completed. Alternatively, Value Line and others with a brighter view of the future do not see a "V" shaped recovery. Instead they see gradual GDP growth which will remain in a range of 2.0% to 2.5% for some time. Additionally, there continues to be limited access to credit markets, the housing market is showing only modest recovery and uncertain wage and job prospects continue. While the prices for common stocks have increased in the last few months, common stock prices are still substantially below the levels that prevailed in late 2007 when the significance of the financial crisis began to be recognized. Given this state of the economy and continuing restrictions on credit availability in financial markets, it is not surprising that equity investors are demanding higher expected returns on equity today than in 2007.

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 equity cost estimates to risks faced by PGE. Based on the Commission's determination that PGE required an upward risk adjustment of 10 basis points in Order No. 07-015, the Commission's determination of a negative risk premium of 10 basis points due to decoupling approved in Order No. 09-020, and unique PGE risks that Mr. Valach, Mr. Hager and I discuss, I conclude that PGE requires, on net, an ROE that is 20 basis points higher than the cost of equity for my benchmark electric utilities sample.

Section III develops my DCF equity cost estimates for a benchmark sample of 31 electric utilities based on three alternative DCF approaches.

Section IV presents three RP analyses. Initially, I explain why it is reasonable to expect equity cost risk premiums to vary inversely with interest rates and present different types of evidence that support such a conclusion. Subsequently, I present equity cost estimates based on three different risk premium approaches.

In Section V, I present a check on the reasonableness of my DCF and RP equity cost estimates based upon recent authorized and earned rates of return on equity ("ROEs") for the sample utilities.

Section VI provides a summary of my analysis, an estimated range in which PGE's cost of equity falls, and my recommended ROE for PGE.

Q. Have you prepared any exhibits to accompany your testimony?

A. Yes. I have prepared 16 exhibits that support my testimony, provided as PGE Exhibits 1201 through 1216.

Q. Please discuss what is meant by a fair rate of return.

A. A fair rate of return is achieved when a utility is authorized rates and rate adjustment mechanisms at levels where the expected return provides common stock investors a reasonable opportunity to earn the cost of common equity. Because operating expenses and interest on debt take precedence over payments to common stock holders, it is the common equity shareholder of the company who bears the greatest risk of receiving expected returns. In 1923, the U.S. Supreme Court set forth the following standards in the Bluefield Waterworks decision:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economic management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally. 262 U.S. 679, 692-93 (1923).

In the Hope Natural Gas Company decision, issued in 1944, the U. S. Supreme Court stated the following regarding the return to owners of a company:

> [T]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. 320 U.S. 591, 603.

In 1989, in Duquesne Light Co. v Barasch the U.S. Supreme Court also recognized two important economic concepts: First, it found that regulatory commissions may need to adjust the risk premium element of the rate of return on equity to provide a fair return. It said:

> [W]hether a particular rate is "unjust" or "unreasonable" will depend to some extent on what is a fair rate of return given the risks under a particular rate setting system . . . .488 U.S. 299, 310.

Therefore, in determining an appropriate return, consideration must be given to the specific risks created by the nature and degree of regulation to which the utility is subject, in addition to examining general economic and financial data for utilities.

In Oregon, the legislature passed ORS 756.040, which puts into state law the principles the U.S. Supreme Court established in the Hope and Bluefield decisions.

Additional risk faced by PGE should be recognized when setting the fair rate for return for the Company. Mr. Valach, Mr. Hager and I explain the unique additional risks of PGE and why PGE requires a higher ROE than the electric utilities in the sample I use to determine guideline cost of equity estimates. In Orders No. 07-015 and No. 09-020, the Commission recognized PGE's RROE may need to differ from returns for other utilities due to higher or lower risks. I estimate the net impact of risks identified by the Commission together with other risks discussed by Mr. Valach, Mr. Hager, and I increase PGE's RROE by 20 basis points above the ROEs required by the benchmark samples of utilities I rely upon to conduct my ROE analyses to reflect greater risks borne by PGE.

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 would ultimately fall on the shoulders of PGE's customers. This 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 in the sample I use to determine benchmark equity costs. PGE has above-average risk from its significant exposure to the wholesale market but below-average risk from decoupling which

is available to most, but not all, utilities in the benchmark sample. PGE is more risky because it is smaller than the average utility in my benchmark sample, has risks related to its large capital expenditures program and is faced with a unique set of risks described by Mr. Valach and Mr. Hager, including risk from SB 408, debt imputation related to purchased power contracts, litigation involving the closure of the Trojan nuclear plant and risks of complying with the Renewable Portfolio Standard. Combined, the net impact of higher risk and benefits increase PGE's cost of equity by no less than 20 basis points above the cost of equity for a typical electric utility.

2. PGE has requested a modification to its PCAM to reduce its risk to a level more in line with the utilities in my benchmark sample. See PGE Exhibit 1203 and my discussion of this issue at page 16 (also see PGE Exhibit 200 and PGE Exhibit 1100). If that is not authorized, its required risk premium above the cost of equity for those benchmark utilities is substantially higher than 20 basis points.

3. The benchmark cost of common equity for the electric utilities samples I use to determine guideline equity costs falls in a range of 10.7% to 11.8% at this time:
    - Three DCF estimates for the electric utilities sample indicate the cost of equity falls in a range of 11.2% to 11.5%;
    - 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 10.7% to 11.8%;
    - Averages of earned ROEs of 10.8% and authorized ROEs of 10.8% corroborate the reasonableness of these RP and DCF equity cost estimates.

4. I conclude that PGE's RROE falls in a range of 10.9% to 12.0% and recommend the Company be authorized an ROE of no less than 11.0%. See PGE Exhibit 1216.

II. Risks of PGE and the Electric Utilities Sample

Q. As a preliminary matter, please discuss the sample of electric utilities you used in your DCF analyses.

A. My DCF sample is composed of the 31 electric utilities listed in PGE Exhibit 1201 of my testimony. These electric utilities are those listed by AUS Utility Reports in categories AUS calls "Electric Companies" and "Combination Electric & Gas Companies" that had an investment grade bond rating from either S&P or Moody's, were vertically integrated companies, had more than 50% of their revenues derived from regulated electric revenues, paid a dividend, and had consensus estimates of analysts' forecasts of growth reported by several sources. PGE Exhibit 1201 lists percentages of revenues from electric operations, Value Line estimates of betas, expected common equity ratios, Standard & Poor's business risk profiles and financial risk profiles, bond ratings, states in which the utilities operate, 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.

Q. Please provide an overview of your discussion of risk.

A. Investors can choose to invest in many different types of assets with varying degrees of risk. Those investments might be in real estate, gold, collections of fine art, or financial assets. The financial assets run the gamut from relatively low risk assets, such as Treasury securities and somewhat higher risk investment grade corporate bonds, to relatively high risk shares of common stocks. As the level of risk increases, investors require higher expected returns. Common stocks of utilities are generally more risky and thus require higher returns than investment grade bonds, which are secured debt instruments with fixed repayment terms. Operating expenses, interest on debt and repayment of principal take precedence over payments to common stock holders, and thus it is the common equity shareholder of the utility who bears the greatest risk of not receiving expected returns. Conceptually,

Required return for common stock	=	Expected Return on a BBB bond	+	risk premium

BBB bonds are the lowest category of investment grade bonds. The required return 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. Compared to the sample of electric utilities in PGE Exhibit 1201, PGE is more risky because it (a) has significant exposure to the wholesale market due to its reliance on wind and hydro generation, (b) is smaller than the average utility in my benchmark sample, (c) has greater risk than in the past due to its larger capital expenditures program, (d) has debt imputation related to purchased power contracts, (e) currently has a PCAM that does not reduce risk as much as the typical PCAM authorized for other electric utilities in my sample, and (f) has other unique risks described by Mr. Valach and Mr. Hager. These risks are offset to some extent by PGE having decoupling.

Q. Does PGE's reliance on hydro power and wind generation increase risk?

A. Yes. Both of these sources of power are subject to unknown and uncontrollable weather conditions and thus power generated from these resources will unavoidably vary from year to year. PGE faces risk related to the cost of replacing that power with power from wholesale markets at costs that are unpredictable. Additionally, the costs of replacing this power are generally expected to be much higher than any cost savings that are expected to occur if the resources produce more power than average. In its August 26, 2009 Ratings Direct Report for PGE, S&P's specifically stated it considered PGE's vulnerability to hydro variability when it assessed PGE's business risk profile. S&P gives PGE a higher risk business risk profile than the average utility I use to determine benchmark costs of equity. See PGE Exhibit 1201. Moody's also stated the variability in hydro was also taken into account when it assessed PGE's risk profile. See Moody's September 24, 2009 Credit Opinion for PGE. PGE's current PCAM mitigates but does not eliminate these unavoidable risks.

Q. Has the Oregon Commission specifically increased PGE's authorized ROE to recognize the added risk of exposure to wholesale markets?

A. Yes. In Order No. 07-015, the Oregon Commission noted PGE had significant exposure to the wholesale market, particularly as compared to PacifiCorp, and increased PGE's authorized ROE by 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 and Mr. Hager address this issue. Some 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 has a negative impact on PGE's credit rating.

Q. Is PGE smaller than the average electric utility in PGE Exhibit 1201?

A. Yes. Based on market values in November 2009, PGE is about 1/5th as large as the average electric utility in PGE Exhibit 1201.

Q. Does PGE's small size increase its risk relative to the sample in PGE Exhibit 1201?

A. Yes. Academic studies have addressed the issue of company size and risk and found that, in general, smaller firms are more risky. The seminal version of CAPM, developed in the mid-1960s, relied upon only beta as the measure of risk. Eugene Fama and Kenneth French ("The Capital Asset Pricing Model: Theory and Evidence," *Journal of Economic Perspectives*, Volume 18, No. 3, Summer 2004 pp. 25-46) provide evidence that questions the usefulness of the simple CAPM and explain that other variables such as company size and various price ratios add to the explanation of stock returns. This problem of choosing the "correct version" of CAPM is, of course, one of the problems with using CAPM to determine equity costs for utilities. But notwithstanding which CAPM version is the correct one, Fama and French did find that company size as well as other factors help explain how investors price common stocks.

Ibbotson Associates (now Morningstar)[1] has examined this issue for a number of years and found that smaller firms require higher and higher returns as size becomes smaller and

[1] Ibbotson Associates was recently purchased by Morningstar.

smaller. (Morningstar, *2009 SBBI Yearbook Valuation Edition*, Chapter 7). I also published an article, "Utility Stocks and the Size Effect - Revisited," *The Quarterly Review of Economics and Finance*, Vol. 43, Issue 3, Autumn 2003, pp. 578-582, which showed smaller utilities are more risky than larger utilities. Combined, this information shows there is no "bright line" that separates smaller, higher risk utilities from larger, lower risk utilities, but that risk and required ROEs increase as utilities are smaller.

Q. Have you determined a specific risk adjustment to compensate PGE for being smaller than the sample you rely upon in PGE Exhibit 1201 to conduct your DCF analyses?

A. No. Morningstar divides companies into ten deciles and then groups those deciles into Large-Cap, Mid-Cap, Low-Cap and Micro-Cap categories. It reports size risk premiums for each of these categories. PGE's size places it in the Low-Cap category. Nine of the utilities in PGE Exhibit 1201 are Large-Cap companies, twelve are Mid-Cap companies and the remaining ten companies are Low-Cap companies. Based on the risk premium estimates reported by Morningstar in 2009, a typical company in the Low-Cap category requires a risk premium that is 154 basis points higher than a company in the Large-Cap category and 66 basis points higher than a company in the Mid-Cap category. See PGE Exhibit 1204. To the extent this study of companies in general applies to utilities, PGE requires an ROE that is higher than 21 of the 31 companies in the electric utilities sample in PGE Exhibit 1201. While I do not determine a specific risk premium addition for size, I do take this evidence into account when determining the risk premium above the equity cost estimates made for the benchmark sample.

Q. In general, do electric utilities face more risk when they have to make additional investments?

A. Yes. Additional capital spending requires utilities to request rate increases to recover returns on and of new rate base additions. Regulatory procedures raise doubts in investors' minds that it is politically possible to request the required increases or that regulators will authorize high enough rates and/or rate adjustment mechanisms to enable the utilities to earn fair rates of return. From an investor's point of view, it is the <u>potential</u> for such disallowances, delays or exclusion from consideration in setting new rates that increases risk. With the need for additional investments, uncertainty arises and the risk increases.

Q. Does PGE plan to invest significantly more than in the past?

A. Yes. PGE has filed an Integrated Resource Plan with the Commission that sets forth its large capital investment program for the next five years. In their most recent credit evaluations of PGE, both Moody's (September 24, 2009) and Standard & Poor's (August 26, 2009) highlight this need for larger capital expenditures in their discussions of PGE's credit quality. Regulatory support to recover costs of these significant new, large capital expenditures is crucial to PGE maintaining access to credit markets at reasonable costs. Mr. Valach and Mr. Hager also address this issue in their testimony.

Q. Does PGE's current PCAM make it more risky than the sample of electric utilities in PGE Exhibit 1201?

A. Yes. PGE provided me with information for a sample of seventeen utilities it had previously considered when it reviewed the types of PCAMs generally available to utilities. This set of utilities is listed in PGE Exhibit 1203. PGE's PCAM analysis is provided as a work paper accompanying PGE Exhibit 200. I considered these seventeen utilities to conduct a peer group analysis of PCAMs. DCF equity cost estimates—which I determine later in my testimony—indicate the sample of seventeen utilities in PGE Exhibit 1203 has approximately the same risk and RROE as the larger sample of 31 utilities in PGE Exhibit 1201. This result indicates that risk reducing benefits of a typical PCAM are already in the cost of equity estimates for the benchmark sample in PGE Exhibit 1201.

While the PCAM authorized for PGE is certainly a step in the right direction and is preferable to no PCAM, it does not reduce risk as much as the typical PCAM authorized for utilities in the peer group sample. Most of the utilities in the peer group sample have PCAMs that offset more uncertainty in power costs and provide better opportunities to recover unavoidable costs than the one currently authorized for PGE. Based on my review of PCAMs and RROEs, I found that unless the current PGE PCAM is revised to be more in line with PCAMs available to other utilities, PGE is more risky than the typical utility in my benchmark sample in PGE Exhibit 1201.

Q. Have you taken the relative risk of PGE's current PCAM into account when you determined your risk premium estimate?

A. No, I did not. PGE has proposed modification of its PCAM to make risks of recovery of power costs more in line with the risks of the peer group and thus I have not increased my recommended risk premium to incorporate the relatively higher risk of PGE's current PCAM.

Q. Do you have any comments about the impact of decoupling on the need for a risk premium?

A. Yes. In Order No. 09-020, this Commission found that adoption of decoupling justified an ROE reduction of 10 basis points for PGE. It is clear that ratings agencies and utilities prefer rate designs with decoupling to traditional rate designs when utilities have risks of losing load due to conservation efforts. I have three observations. First, in its September 24, 2009 Credit Opinion, Moody's says it views decoupling mechanisms as credit positive for utilities but noted that similar mechanisms exist for a growing number of utilities around the country. Before determining if a negative risk premium (an ROE lower than the benchmark cost of equity for a sample of electric utilities) is required due to decoupling, it should be determined if the risk-reducing benefits of decoupling are already in the benchmark costs of equity estimates. PGE Exhibit 1201 shows 17 of the 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 and three more have approval of decoupling mechanisms pending. 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 most utilities in the sample already reflect the benefit of such rate designs (whatever that benefit is). Second, if there is a benefit for investors from decoupling, I expect the impact on RROE is small. Third, decoupling may be required simply to offset higher risks that occur when conservation initiatives are pressed by government agencies and utilities. However, until all electric utilities in the sample used to determine benchmark equity costs have decoupling or alternative fixed cost recovery mechanisms, I conclude a benefit of 10 basis points is not unreasonable and I take it into account when I determine my risk premium estimate for PGE.

Q. What is your recommended risk adjustment for PGE?

A. In Order No. 07-015, the Commission determined that PGE requires a risk premium of 10 basis points to compensate for its significant exposure to the wholesale market. That risk continues and increases due to uncertainty of production from wind projects as well as hydro projects. PGE is more risky than in the past when it had a much more modest capital expenditures program, is more risky because it is only 1/5th as large as the benchmark sample and has a higher than average percentage of purchased power. PGE is also more risky than the sample due to other unique risks Mr. Valach and Mr. Hager discuss in their testimony. It is, however, somewhat less risky than some of the utilities in the benchmark sample due to its decoupling rate design. Taking into account PGE's exposure to all of these various positive and negative risks, I recommend the Commission adopt a risk premium of 20 basis points when it determines PGE's authorized ROE.

Q. Is your recommended risk premium consistent with the indicators of risk in PGE Exhibit 1201?

A. Yes. Risk indicators in PGE Exhibit 1201 corroborate my recommended risk premium of 20 basis points for PGE. They show PGE has the same or higher risk than the sample average utility. PGE is more risky with respect to beta estimates, S&P business risk profiles, size, and percentage of purchased power. Recognizing rating agencies impute debt to PGE for its above-average percentage of purchased power, PGE is also more risky with respect to its equity ratio. S&P reduced PGE's corporate credit rating to BBB and reduced its senior secured rating to A- from A in January 2010. S&PCorrect: Portland General Electric Co. Corporate Credit Rating Lowered to 'BBB' on Weak Economy (January 29, 2010). After the downgrading, PGE has approximately the same risk as the sample based on S&P financial risk profiles and bond ratings of both Moody's and S&P.

III. DCF Equity Cost Estimates

Q. Do you have preliminary comments related to the use of the DCF model to determine equity cost estimates?

A. Yes. Given the weight the Commission has given to the DCF model in recent Oregon decisions, I begin my RROE study with my DCF estimates. However, I strongly recommend the Commission consider several versions of the DCF model and other useful information to determine a fair ROE for PGE. The DCF model depends crucially on assumptions about constant or multi-period growth rates in the future. We do not, however, know exactly how investors form their opinions about these growth rates. Not only are there unavoidable difficulties with estimating growth rates but also investors may consider information and financial models other than the DCF model to price stocks. Other methods assume investors make decisions in different ways and thus it is appropriate to make different abstractions to model investor behavior. There is no guarantee that any particular method is the "right" one and thus superior to others. It follows then that other reasonable approaches should be considered.

At a minimum, other financial models and the data regarding authorized and earned ROEs in PGE Exhibit 1215 should be used as a check on the specific DCF assumptions and methods being employed. Several methods and large samples of comparable risk companies should be relied upon to make those estimates whenever possible. If the equity costs produced with DCF methods and assumptions chosen by an analyst are significantly different than equity costs resulting from application of other financial models and checks on the reasonableness of the results made by examination of authorized and earned ROEs, those DCF results should be seriously questioned or rejected.

Q. Please summarize your DCF estimates.

A. My DCF estimates are provided in PGE Exhibit 1207, 1209 and 1210. The estimates presented in PGE Exhibit 1207 are based on the constant growth DCF model and forward-looking estimates of growth. PGE Exhibit 1207 relies on an average of analysts' forecasts of growth reported by Zacks, Yahoo! Finance, Reuters and Value Line and finds the benchmark cost of equity is 11.5%. PGE Exhibit 1209 relies on concepts the Federal Energy Regulatory Commission ("FERC") used to estimate equity costs with its multi-period DCF growth model, a forecast of GDP growth and ranges of the growth forecasts reported by Zacks, Yahoo! Finance, Reuters and Value Line. This method finds the estimated DCF equity cost for the benchmark sample is also 11.5%. 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 11.2% for the sample. After recognizing PGE requires a risk premium above the benchmark cost of equity estimates of 20 basis points, the indicated ROE range for PGE is 11.4% to 11.7%.

Q. Please explain the 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"). Generally, the constant growth model is computed with formula (1) or (2):

(1) $$\text{Equity Cost} = D_0/P_0 \times (1 + g) + g$$

(2) Equity Cost = D_1/P_0 + 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 or relying on an independent forecast of D_1. The constant growth DCF model and multistage DCF models are derived from the valuation model shown in equation 3 below:

(3) $P_0 = D_1/(1+k) + D_2/(1+k)^2 + \ldots + D_\infty/(1+k)^\infty$,

where k is the cost of equity; P_0 is the current stock price, D_1, D_2, . . . 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, DPS, earnings per share ("EPS"), stock prices and book values 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, book values and stock prices are assumed to grow at faster or slower rates than in the initial stage (or stages).

Q. How did you compute the dividend yields?

A. My dividend yield estimates are denoted as D_1/P_0 in equation (2) above. These estimates are reported in PGE Exhibit 1205. My dividend yields are averages of the highest and lowest dividend yields which occurred during the period September 1, 2009 to November 30, 2009. My estimates of D_1 are Value Line's estimated dividends for the next 12 months reported by Value Line in its December 4, 2009 Summary and Index which I have adjusted to compensate for the time value of money.

Q. Why have you adjusted the values for D_1 for the time value of money?

A. This adjustment is required because equation (3) above assumes dividends are paid once a year but investors receive dividend payments on a quarterly basis. If a utility pays a dividend of $100 per year, investors would prefer to be paid $25 every quarter instead of $100 at the end of the year. Prices investors pay for utility stocks reflect the benefit investors receive by utilities paying dividends every quarter but equation (3) assumes the $100 is paid only once a year. My calculation adjusts the dividend upward by just enough to offset the time value of receiving the $100 in four quarterly installments of $25 each.

The values adopted for D_1 must also reflect the fact that DPS are expected to increase over time since all of the utilities in the sample are projected to have growth in the future. I recognize that potential positive growth by adopting Value Line's forecasts of dividends for the next 12 months. Other methods could be adopted to recognize the near-term growth in DPS, but I have used this conservative approach to minimize controversy. A general discussion of the various approaches that could be taken is provided in Roger Morin, <u>New Regulatory Finance</u>, pages 343-349.

Q. How did you estimate growth rates?

A. Growth rates used with the DCF model should be based on the best available forecasts of future growth. A number of investor services report consensus averages of analysts' forecasts of growth. For my analysis, I have relied on the consensus of long-term EPS growth rates reported by Zacks, Reuters and Yahoo! Finance as well as long-term EPS growth rates determined or reported by Value Line[2]. PGE Exhibit 1206 provides a list of the

[2] Northwestern Corp is in Value Line's Small and Mid-Cap Edition and thus Value Line does not determine an estimate of future growth. Instead, it reports a consensus of five analysts' predictions of long-term EPS growth for the utility.

available analysts' forecasts reported for the sample utilities by the four institutions. Column (e) of PGE Exhibit 1206 reports averages of the available analysts' forecasts. To be included in the sample, I required that at least three of the institutions reported an estimate of growth for the utility in question. Taken together, the average of the analysts' forecasts provided by all four of the institutions is 6.4% at this time. Based on this average of growth rate estimates and dividend yields from PGE Exhibit 1205, the indicated cost of equity for the benchmark sample is 11.5% at this time. See PGE Exhibit 1207.

Q. Please explain your second DCF analysis.

A. My second DCF analysis is a two-stage DCF analysis based on concepts 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 concepts I rely upon 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 equity cost 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) analyst's forecast in the range of growth rates reported in PGE Exhibit 1208. With this approach, the FERC method also eliminates from consideration any equity cost estimate that is not greater than 40 basis points above the cost of A-rated bonds. That requirement is reasonable because costs of equity for utilities should always exceed the cost of investment-grade debt. In my analysis, to be conservative, I did not eliminate such equity cost estimates.

Q. How did you estimate GDP growth for the second stage of this 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 in the next few years. Reasonable estimates of long-term GDP growth would consider not only forecasts of future GDP growth but GDP growth that has occurred during long periods in the past.

In determining my estimate of GDP growth, I considered past long-term annual average GDP growth of 6.7% which Staff of the Arizona Corporation Commission relied on to determine growth for the second stage of its multi-stage DCF analysis (Direct Testimony for ACC Staff of Steven P. Irvine, in Docket No. W-01303A-07-0209 (Arizona-American Water Company), dated October 15, 2007, page 26). I updated and revised that historical average to obtain a forward-looking estimate of GDP growth by reducing the updated growth rate by past average inflation of 3.1% (reported by Morningstar in Table 2-1 of *Ibbotson SBBI 2009 Valuation Yearbook),* and replacing it with a forecast of the future inflation of 3.0% (Value Line, *Quarterly Economic Review*, November 27, 2009) to determine a forward-looking estimate of GDP growth of 6.6% (i.e., 6.7% minus 3.1% plus 3.0% = 6.6%). I also consider a forecast of GDP growth in 2013 from Value Line estimates of future real GDP growth of 3.3% in 2013 and the future GDP deflator of 1.7% in 2013 to estimate future near-term GDP growth of 5.1% (1.051 = 1.033*1.017). These forecasts are provided by Value Line in its *Quarterly Economic Review,* dated November 27, 2009. Based on an average of those estimates of 6.6% and 5.1%, I determined a forward-looking estimate of GDP growth of 5.8% for my analyses.

Q. What are the results of your two-stage DCF analysis?

A. The results are reported in PGE Exhibit 1209. The average of the high equity cost estimates is 12.9% and the average of low equity cost estimates is 10.1%. The mid-point of that equity cost range is 11.5%. In applying this method, I considered dropping the low equity cost estimates for Edison International of 6.56% and for Great Plains Energy of 7.14% because they are either below or equal to the expected future cost of Baa bonds. Compare PGE Exhibit 1209 with PGE Exhibit 1211. As previously discussed, FERC's standard method is to remove from consideration any estimated equity cost that is not 40 basis points above the cost of A-rated bonds. Such a principle is appropriate for any equity cost approach because all credible estimates of the cost of equity for utilities must be higher than the yield on investment grade bonds. Baa bonds are investment grade bonds. Thus, the FERC criteria places the equity cost estimates for Edison International and Great Plains below the level which should be included. To be conservative, however, I have not eliminated them. If they were removed, the average of low equity cost estimates of 10.1% would increase to 10.3%.

Q. Why is the preliminary range of equity cost estimates so wide?

A. It is this wide because it is based on the highest and lowest forecasts of growth from PGE Exhibit 1208, not consensus estimates of growth. While it is generally not appropriate to base an equity cost estimate on either of those extreme values, the FERC approach recognizes the mid-point of that range provides a reasonable equity cost estimate. Based on the range of EPS growth forecasts reported by four institutions, the indicated average cost of equity for the sample is 11.5% and thus the indicated cost of equity for PGE is 11.7%.

Q. Please describe your third DCF analysis.

A. My third DCF analysis is developed in PGE Exhibit 1210. This analysis determines the cost of equity by finding the internal rate of return that is consistent with different growth rates in three stages. Initially, it is assumed that an average of recent prices ("P_{2009}") and *Value Line's* forecasted dividends for the next 12 months reported by *Value Line* at December 4, 2009 in its Summary & Index ("D_{2010}") are appropriate for the analysis. Growth rates adopted for the first stage (for 2011-2015, the next five years) are the averages of forecasted EPS growth rates reported in PGE Exhibit 1206. 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_{2011} and D_{2015}) 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 (2016 to 2025). PGE Exhibit 1210 reports the first and last forecasted cash distributions for this period (D_{2016} and $(P+D)_{2025}$) for each utility. The terminal growth rate is assumed to be GDP growth of 5.8% which I discussed above. In 2025 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 equity cost estimate based on this third DCF approach?

A. This analysis indicates an average cost of equity estimate for the benchmark sample companies is 11.2% and thus the indicated cost of equity for PGE is 11.4%.

IV. Risk Premium Equity Cost Estimates

Q. Please turn to your risk premium equity cost estimates. Please summarize the equity cost estimates you make with this approach.

A. I make three RP equity cost estimates that indicate the cost of equity for PGE falls in a range of 10.9% to 12.0%. 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 an equity cost determined with a risk premium approach?

A. A risk premium equity cost is made by first determining what the relationship has been between equity costs and interest rates over a period of time. Then that relationship is combined with a current forecast of the interest rate to predict the current cost of equity. Generally such equity cost estimates depend on different assumptions about how investors price stocks than are assumed when making DCF equity cost estimates.

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 2011.

A. In 2005, annual averages of various interest rates dropped to the lowest levels that have occurred in close to forty years. From 1976 to 2002, annual average rates for Baa Corporate bonds, for example, ranged from 7.80% to 16.11%. In 2005, that annual average was only 6.06%. For comparison, in 2009 the annual average for Baa Corporate bond rates was 7.29% and is expected to average 7.14% in 2011-2013. See PGE Exhibit 1211. My analyses below recognize that interest rates are expected to be lower in the future than during most years in the past.

Q. Why have you used the period 2011-2013 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 2011. I do not know when PGE will file for different rates but anticipate the new rates set for 2011 will be in effect for more than one year. As a result, I have adopted the period 2011-2013 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 interest rates in 2011-2013 are expected to be lower than historical averages and thus risk premiums in 2011-2013 are expected to be higher. While interest rates have increased somewhat since 2003, the average Baa rates expected in 2011-2013 are lower than average Baa rates were during periods used to determine historical relationships between interest 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. In California, the 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 and 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. More recently, in California D.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 Department of Ratepayer Advocates of the California PUC to determine equity costs for utilities (see Division of Ratepayer Advocates, California PUC Report on the Cost of Capital, San Jose Water, June 2006, Application 065-02-014). This method relies on annual averages of past recorded book returns on equity for a sample of utilities as proxies for average costs of equity. It assumes that regulators adopt rates and rate adjustment mechanisms that give utilities reasonable opportunities to earn their RROEs and thus—though each individual utility may earn more or less its RROE in a given year—the average of the sample ROEs provides a useful proxy for the average cost of equity for the sample.

Q. How did you implement this method in this case?

A. To make this analysis, I adopted averages of earned ROEs for the twelve surviving utilities in the sample adopted by the Oregon PUC Staff in UE 180 as the proxies for annual average equity costs during the years 1999 to 2008. PGE did not support Staff's sample group in UE 180 and in Order No. 07-015, the Commission found estimates of the cost of equity made with data for that sample were "uniformly low." Using the UE 180 Staff sample group for a risk premium equity cost estimate is thus a means to provide a conservative and relatively non-controversial estimate of PGE's cost of equity. To prepare this analysis, I used data for annual earnings per share from 1999 to 2008 and beginning and ending book values for 1998 to 2008 reported by Value Line.

Q. What are the results of this first RP analysis?

A. This risk premium analysis indicates the estimated average cost of equity for the surviving utilities in the electric utility sample adopted by the Staff in UE-180 falls in a range of 10.9% to 11.3%. As expected from the evidence I presented above, the estimated average risk premium in the most recent 5-year period is somewhat higher than the average range for the full 10-year period. This result is expected because average interest rates were lower in 2004-2008 than in 1999-2008. My analysis is reported in PGE Exhibit 1212. Forecasts of interest rates expected in 2010-2013 are reported in PGE Exhibit 1211.

Q. What are the results of your second RP analysis?

A. My second approach computes the risk premium as the average of realized market return premiums over a period of time. This analysis indicates the cost of equity for a typical electric utility falls in a range of 10.7% to 11.8% and thus the indicated cost of equity for PGE falls in a range of 10.9% to 12.0%.

Q. Please discuss this second risk premium analysis.

A. The second risk premium analysis is a market approach. Results of this method are reported in PGE Exhibit 1213. It is based on an average of differences between annual total realized returns for Moody's index of electric utilities and yields on Baa 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 which was required during that period.

Initially, I computed two preliminary average risk premiums. The first preliminary risk premium is for the period ending in the year 2000 when Moody's stopped updating this index. The second preliminary estimate was for the full period ending in 2008. It is based on my update of the Moody's sample using data for surviving utilities from the original Moody's sample of 24 utilities with data for the period 2001 to 2008. I report the results for both the original period and the updated period to determine this second RP estimate of the cost of equity.

The preliminary analyses determine average risk premiums and thus do not incorporate the expectation that risk premiums vary inversely with interest rates. Since a Baa bond rate of 7.14% expected in 2011-2013 is lower than the average of Baa rates of 7.9% for the period 1950 to 2008 and lower than the average interest rate of 8.1% during the period of the original study, the future risk premium is expected to be slightly higher than the simple average RP based on past data. To incorporate this additional information, I adjusted the risk premium estimates upward by assuming the cost of equity changes by half as much as the difference in Baa bond rates. This adjustment is consistent with the California PUC orders I discussed above. Based on these estimates, the benchmark equity cost range is 10.7% to 11.8% and the indicated cost of equity for PGE falls in a range of 10.9% to 12.0%.

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 and extends the FERC analysis by recognizing risk premiums increase (decrease) as interest rates decrease (increase).

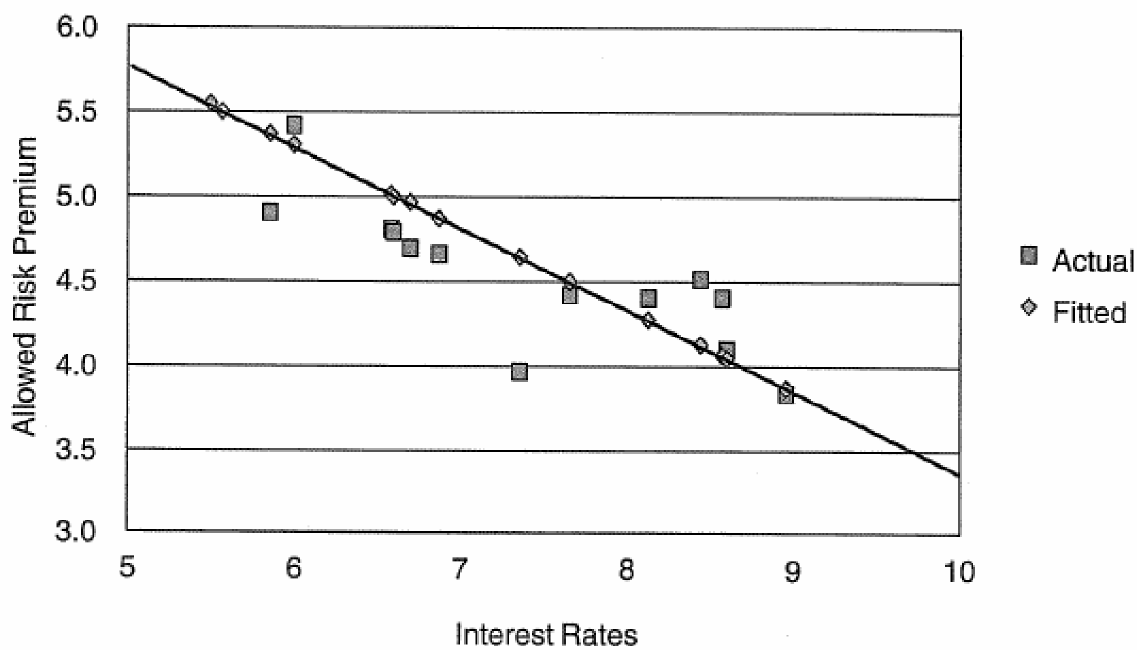
Q. Please discuss Dr. Morin's approach.

A. Dr. Morin reports that risk premium equity cost estimates have been used 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 (RP) and Treasury rates (YIELD) for the period 1987 to 2005 for electric utilities:

$$(5) \qquad RP = 8.2049 - \underset{(t = -8.4)}{0.4833} \times YIELD \qquad R^2 = 0.81$$

where allowed equity returns reported by Regulatory Research Associates ("RRA") are adopted as the proxies for equity costs. To obtain a cost of equity estimate, Dr. Morin inserts a current or projected Treasury bond yield in his estimated equation. He further explains, "Figure 4-4 shows the clear inverse relationship between the allowed risk premium and interest rates revealed in past common equity decisions." The risk premium method presented by Dr. Morin is discussed in Section 4.5 of his 2006 book and is shown graphically in Figure 4-4 reproduced below:

FIGURE 4-4
ALLOWED RISK PREMIUM VS INTEREST RATES
1987–2005



The risk premiums reported in the figure are the costs of equity 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 new 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 491 individual litigated decisions. Dr. Morin relied upon annual averages of decisions reported by RRA instead of individual decisions. I have also based my analysis on Baa bond rates six months prior to the dates decisions were issued by the commissions. That approach recognizes the practical constraints of regulatory proceedings in which DCF, RP and other financial models used to determine authorized ROEs are based on data available several months prior to the issue of orders. Baa bond rates instead of Treasury rates are adopted to determine the risk premiums based on the analysis presented in PGE Exhibit 1202 and discussed above.

Q. What specific study did you conduct?

A. I conducted an analysis with 491 observations for the period 1985 to 2008. This analysis is based on more detailed data and is for a period that is 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 face a cost of equity of 10.9% in 2011-2013. As PGE is more risky than the typical electric utility, once a 20 basis point risk adjustment for PGE is recognized, this model indicates a point estimate of PGE's cost of equity of 11.1%. That equity cost estimate for PGE falls within the range of equity cost estimates made with the other two RP approaches and thus corroborates those other analyses.

V. Authorized and Earned ROEs

Q. Have you made any checks on the reasonableness of your DCF and RP equity cost estimates?

A. Yes. 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. I present PGE Exhibit 1215 to provide such a gauge.

Q. Does PGE Exhibit 1215 provide perspective about what is a fair ROE for PGE at this time?

A. Yes. As I noted above, the U.S. Supreme Court's decisions in the 1923 Bluefield Waterworks case and 1944 Hope Natural Gas Company case, as well as ORS 756.040 set forth three standards for a fair ROE. In effect, Oregon and the U.S. Supreme Court require the Commission to determine rates and rate adjustment mechanisms for PGE that allow the Company to have a fair chance to earn its opportunity cost of capital, *i.e.*, returns investors could expect to earn if they invest in other enterprises of comparable risk. A benchmark sample of those other enterprises of comparable risk is the guideline sample of 31 electric utilities.

The two obvious measures of the opportunity cost of equity that are available to investors are the ROEs these benchmark utilities are currently earning and the ROEs these utilities are authorized to earn. If regulators authorize rates and rate adjustment mechanisms that allow utilities a reasonable chance to earn their costs of equity, since PGE is more risky than the benchmark sample, either an average of earned ROEs for the sample or an average of authorized ROEs provide information about the minimum ROE that should be authorized for PGE.

PGE Exhibit 1215 provides a list of currently authorized ROEs and earned ROEs reported by AUS Utility Reports in December 2009 for the utilities in PGE Exhibit 1201. These data indicate the sample companies earned, on average, 10.0%. An individual earned ROE, however, does not provide a useful estimate of the cost of equity if it is less than the cost of investment grade debt. As FERC has recognized, such numbers do not provide realistic estimates of the cost of equity and should be disregarded. Once earned returns below the cost of investment grade bonds are removed from the list, the remaining average of earned ROEs is 10.8%.

PGE Exhibit 1215 also reports the most recently authorized ROEs for the 31 sample utilities as reported by AUS Utility Reports. Based on these data, the benchmark electric utilities are authorized an average ROE of 10.8%.

Q. Do the earned and authorized ROEs reported in PGE Exhibit 1215 depend upon the types of models used to determine those ROEs or the assumptions used to produce equity costs with those models?

A. No, they do not. The evidence in PGE Exhibit 1215 provides a direct estimate of the opportunity cost of equity that ORS 756.040 and the U.S. Supreme Court have found should be considered in determining a fair rate of return on equity. The ultimate test of a fair ROE is whether the rates and rate adjustment mechanisms authorized for PGE by the Oregon PUC give PGE a reasonable opportunity to earn the rate of return investors could expect to earn if they invested in another utility of comparable risk. The average of authorized returns and realized ROEs resulting from commission decisions reported in PGE Exhibit 1215 provide a gauge indicating the equity cost estimates I present above are indeed reasonable. Once a risk premium of 20 basis points is recognized, the indicated fair ROE for PGE is 11.0%.

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, and other risks discussed by Mr. Valach, Mr. Hager, and me. PGE continues to require a risk adjustment of 10 basis points to compensate for its exposure to the wholesale market. Once decoupling and other risk factors are considered, PGE requires a combined risk adjustment of no less than 20 basis points to compensate for its above-average risks.

My equity cost estimates are summarized in PGE Exhibit 1216. Initially, I turned to benchmark DCF estimates based on data for a sample of 31 electric utilities. My first estimate for the benchmark sample of 11.5% is based on the constant growth DCF model and consensus estimates of future EPS growth reported by Reuters, Zacks, Yahoo! Finance and Value Line. My second benchmark DCF estimate of 11.5% is based on concepts used by FERC, a range of growth estimates presented in PGE Exhibit 1206 by the four institutions, 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 11.7%. 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 11.2% and the indicated RROE for PGE is 11.4%.

In section IV, I explain why risk premiums are expected to vary inversely with interest rates and summarize Gordon and Halpern's theory that supports such a relationship. I then present three risk premium studies that used different methods to determine risk premiums: one bases risk premiums on realized book returns on average equity, one determines risk premiums from averages of holding period returns and the other determines risk premiums from a statistical analysis of past authorized returns for electric utilities in which the cases were litigated. Taken together, the risk premium analyses support a benchmark ROE range of 10.7% to 11.8% and an equity cost range of 10.9% to 12.0% for PGE.

I also provide some perspective and checks on my estimates of RROEs. I show that if authorized and earned ROEs for companies in my DCF benchmark sample were considered along with a risk adjustment for PGE of 20 basis points, the indicated fair ROE for PGE would be 11.0%. Taking into account all of the data presented in PGE Exhibit 1216, I estimate PGE's cost of equity falls in a range of 10.9% to 12.0% and recommend it be authorized an ROE of no less than 11.0%.

Q. Is PGE'S requested ROE of 10.5% reasonable?

A. Yes, it is. A 10.5% ROE is below the bottom of my range of equity cost estimates and thus is a conservative request.

VII. Qualifications of Thomas M. Zepp

Q. What is your profession and background?

A. I am an economist and Vice President of Utility Resources, Inc., a consulting firm. I received my Ph.D. in Economics from the University of Florida. Prior to jointly establishing our consulting firm in 1985, I was a consultant at Zinder Companies from 1982-1985. Between 1976 and 1982, I was a senior economist on the staff of the Oregon Public Utility Commissioner. In that position, I conducted studies and prepared testimony on a number of economic and financial issues and estimated fair rates of return for many of the utilities regulated by the Commissioner. Prior to 1976, I taught business and economics courses at the graduate and undergraduate levels at the University of Florida, Central Michigan University and the Joint Graduate Program of Armstrong and Savannah State Colleges.

I have been deposed or testified on various topics before regulatory commissions, courts and legislative committees in states of Alaska, Arizona, California, Colorado, Georgia, Hawaii, Idaho, Illinois, Iowa, Kentucky, Minnesota, Montana, Nebraska, Nevada, New Mexico, Oklahoma, Oregon, Tennessee, Utah, Washington, West Virginia, and Wyoming, before two Canadian regulatory authorities and before four Federal agencies. In addition to cost of capital studies, I have testified as to values of utility properties, incremental costs of energy and telecommunications services, and appropriate rate designs.

Q. What cost of capital studies have you prepared before?

A. I have submitted studies or testified on cost of capital and other financial issues before the Interstate Commerce Commission, Bonneville Power Administration, and courts or regulatory agencies in fifteen states.

My studies and testimony have included consideration of the financial health and fair rates of return for General Telephone of the Northwest, Illinois Bell Telephone, Nevada Bell Telephone, Pacific Northwest Bell, US WEST, Alaska Power Company, Anchorage Municipal Light & Power, Black Bear Lake Hydro, Inc., Commonwealth Edison, Idaho Power, Iowa-Illinois Gas and Electric, Pacific Power & Light, Portland General Electric, 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 have 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 complete your prefiled testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
1201	Comparison of PGE and the DCF Electric Utilities Sample
1202	Past and Current Spreads Between Treasury Rates and Baa Bonds
1203	Utilities in Peer Group Analysis with PCAMs for Electric Operations in All States
1204	Evidence Showing Risk Increases as the Market Values of Companies Decrease
1205	Current Annualized Average Dividend Yields for Electric Utilities Sample
1206	Estimates of Growth Based on Analysts' Forecasts Reported by Value Line, Reuters, Yahoo! Finance and Zacks
1207	Application of the Constant Growth DCF Model
1208	Range of Growth Rates Reported by Four Investor Services
1209	Application of the FERC Multi-period DCF Method
1210	Alternative Multi-Stage DCF Growth Analysis
1211	Forecasts of Treasury and Baa Corporate Bond Rates
1212	Risk Premium Analysis: Method Used by Department of Ratepayer Advocates of the California PUC with Data for Oregon PUC Sample - 1999 to 2008
1213	Risk Premium Analysis Based on Holding Period Returns for Moody's Electric Utilities Sample as Updated, 1950 to 2008
1214	Risk Premiums Determined by Relationship between Authorized ROEs and Baa Corporate Bond Rates During the Period 1985-2008
1215	Earned and Authorized ROEs for Electric Utilities Sample
1216	Estimated Costs of Equity for Benchmark Samples and PGE

Portland General Electric Company

PGE Exhibit 1201 (page 1)

Comparison of PGE to the DCF Electric Utilities Sample

		Percentage of Electric Revenues[a/]	Value Line[b/] Betas	Expected[c/] Common Equity Ratio	S&P Business Risk Profile	S&P Financial Risk Profile	S&P Bond Rating	Moody's Bond Rating
1	Allegheny Energy, Inc.	90%	0.95	49.0%	Strong	Aggressive	BBB+	Baa1
2	ALLETE, Inc.	90%	0.70	51.5%	Strong	Significant	A-	A2
3	Alliant Energy Corporation	71%	0.70	60.5%	Excellent	Significant	A-	A2
4	Ameren Corporation	82%	0.80	54.0%	Satisfactory	Significant	BBB	Baa1
5	American Electric Power Co.	94%	0.70	48.0%	Excellent	Aggressive	BBB	Baa2
6	Avista Corporation	54%	0.70	48.5%	Excellent	Aggressive	BBB+	Baa1
7	Cleco Corporation	95%	0.65	52.5%	Excellent	Aggressive	BBB	Baa1
8	CMS Energy Corporation	54%	0.80	31.5%	Excellent	Aggressive	BBB	A3
9	DPL Inc.	100%	0.60	47.0%	Excellent	Intermediate	A	Aa3
10	DTE Energy Company	57%	0.75	44.5%	Strong	Significant	A-	A2
11	Duke Energy Corporation	79%	0.65	51.5%	Excellent	Significant	A	Baa2
12	Edison International	81%	0.80	46.0%	Strong	Aggressive	A	A1
13	Empire District Electric Co.	86%	0.75	49.0%	Strong	Aggressive	BBB+	Baa1
14	Entergy Corporation	75%	0.70	44.0%	Strong	Significant	A-	Baa1
15	FPL Group, Inc.	72%	0.75	44.5%	Excellent	Intermediate	A	Aa2
16	Great Plains Energy Incorporated	100%	0.75	48.0%	Excellent	Aggressive	BBB+	A3
17	Hawaiian Electric Industries, Inc.	99%	0.70	55.5%	Strong	Significant	BBB	Baa2
18	IDACORP, Inc.	100%	0.70	51.0%	Excellent	Aggressive	A-	A3
19	MGE Energy, Inc.	60%	0.65	65.0%	Excellent	Intermediate	AA-	Aa2
20	Northwestern Corporation	66%	nmf	53.2%	Excellent	Aggressive	A-	A1
21	OGE Energy Corp.	61%	0.75	46.5%	Strong	Significant	BBB +	Baa1
22	PG&E Corporation	76%	0.55	54.0%	Excellent	Intermediate	BBB+	A3
23	Pinnacle West Capital Corp.	97%	0.75	52.0%	Strong	Significant	BBB-	Baa2
24	Portland General Electric	96%	0.75	50.0%	Strong	Significant	A-	A3
25	Progress Energy Inc.	96%	0.65	47.5%	Excellent	Aggressive	A-	A1
26	Southern Company	99%	0.55	42.5%	Excellent	Intermediate	A	A2
27	TECO Energy, Inc.	66%	0.85	41.5%	Excellent	Aggressive	BBB	Baa1
28	UniSource Energy Corporation	85%	0.70	40.0%	n/a	n/a	BBB+	NR
29	Westar Energy, Inc.	73%	0.75	52.5%	Excellent	Aggressive	BBB	Baa1
30	Wisconsin Energy Corporation	63%	0.65	45.5%	Excellent	Aggressive	A-	A1
31	Xcel Energy Inc.	79%	0.65	48.5%	Excellent	Significant	A	A2
	Average	81%	0.71	48.9%	Excellent[d/]	Significant[d/]	A-[d/]	A3[d/]
	Portland General	96%	0.75	50.0%	Strong	Significant	A-[e/]	A3

Notes and Sources

a/ AUS Utility Reports, December 2009.
b/ Value Line, *Investment Survey, Summary & Index,* December 4, 2009.
c/ Value Line forecasts of equity ratios for all but Northwestern Corp. Northwestern Corp is 2008 actual.
d/ Median rating of sample firms
e/ Company data for PGE. S&P Bond rating for PGE after downgrade in January 2010.
n/a Not available

Portland General Electric Company

PGE Exhibit 1201 (page 2)

Comparison of PGE to the DCF Electric Utilities Sample

		States in which Utility Operates	Decoupling Available in at Least One State [f/]	Market Capitalization [g/] ($ millions)	Percentage of Purchased Power [h/]
1	Allegheny Energy, Inc.	PA, WV, MD, VA	Yes	$3,856	n/a
2	ALLETE, Inc.	MN, WI	Yes	$1,168	31%
3	Alliant Energy Corporation	WI, IA, MN	Yes	$3,081	23%
4	Ameren Corporation	IL, MO	No	$5,627	18%
5	American Electric Power Co.	11 states	Yes	$15,320	n/a
6	Avista Corporation	ID, OR, WA	Yes	$1,097	35%
7	Cleco Corporation	LA	No	$1,558	56%
8	CMS Energy Corporation	MI	Pending	$3,314	52%
9	DPL Inc.	OH	Yes	$3,179	n/a
10	DTE Energy Company	MI	Pending	$6,633	14%
11	Duke Energy Corporation	NC, SC, OH, IN, KY	Yes	$21,060	8%
12	Edison International	CA	Yes	$11,054	64%
13	Empire District Electric Co.	MO, KS, OK, AR	Yes [j/]	$641	39%
14	Entergy Corporation	AR, LA, MS, TX	No	$15,605	39%
15	FPL Group, Inc.	FL	No	$21,212	14%
16	Great Plains Energy Incorporated	KS, MO	No	$2,454	15%
17	Hawaiian Electric Industries, Inc.	HI	Pending	$1,778	40%
18	IDACORP, Inc.	ID, OR	Yes	$1,396	50%
19	MGE Energy, Inc.	WI	Yes	$829	39%
20	Northwestern Corporation	MT, NE,SD	No	$998	n/a
21	OGE Energy Corp.	OK, AR	Yes [j/]	$3,351	14%
22	PG&E Corporation	CA	Yes	$16,529	64%
23	Pinnacle West Capital Corp.	AZ	No	$3,408	25%
24	Portland General Electric	OR	Yes	$1,469	47% [k/]
25	Progress Energy Inc.	NC, SC, FL	Yes [j/]	$10,833	14%
26	Southern Company	GA, AL, FL, MS	No	$25,526	5%
27	TECO Energy, Inc.	FL	No	$3,162	15%
28	UniSource Energy Corporation	AZ	No	$1,089	0%
29	Westar Energy, Inc.	KS	No	$2,220	1%
30	Wisconsin Energy Corporation	WI, MI	Yes	$5,299	36%
31	Xcel Energy Inc.	8 states	Yes	$9,163	n/a
	Average		Yes [i/]	$6,578	29%
	Portland General		Yes	$1,469	47%

Notes and Sources

f/ IEE, State Energy Efficiency Regualtory Frameworks, Summary Table, January 2010.
g/ Number of shares times price per share at November 16, 2009 as reported by AUS Utility Reports in December 2009.
h/ Value Line Investment Survey Issue 1 (dated Novbember 27, 2009), the Standard Issue 5 and the Small and Mid Cap Issue 5 (dated September 25, 2009) and Issue 11 (dated November 6, 2009).
i/ Median of sample firms
j/ Fixed cost recovery provided by a Lost Revenue Adjustment Mechanism instead of decoupling.
k/ Company data for PGE.
n/a Not available

Portland General Electric Company

PGE Exhibit 1202

Past and Current Spreads Between Treasury Rates and Rates for Baa Bonds

Past Actual Rates (1990 to 2007)[a/]

Year	30-Year Treasury Rates	Baa Rates	Spread
1990	8.61%	10.36%	1.75%
1991	8.14%	9.80%	1.66%
1992	7.67%	8.98%	1.31%
1993	6.59%	7.93%	1.34%
1994	7.37%	8.63%	1.26%
1995	6.88%	8.20%	1.32%
1996	6.71%	8.05%	1.34%
1997	6.61%	7.87%	1.26%
1998	5.58%	7.22%	1.64%
1999	5.87%	7.88%	2.01%
2000	5.94%	8.37%	2.43%
2001	5.49%	7.95%	2.46%
2002	5.42%	7.80%	2.38%
2003	5.05%	6.76%	1.71%
2004	5.12%	6.39%	1.27%
2005	4.56%	6.06%	1.50%
2006	4.91%	6.48%	1.57%
2007	4.84%	6.48%	1.64%
Average	6.19%	7.85%	1.66%
2008	4.28%	7.44%	3.16%
2009	4.08%	7.29%	3.21%

Expected spread in 2010[b/]	2.00%
Expected average spread for 2011-2013[c/]	1.97%

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/ Expected spread derived from December 2009 Blue Chip consensus forecasts of 6.8% for Baa bonds and 4.8% for 30-year Treasury securities for fourth quarter 2010.

c/ From data in Exhibit 1211.

Portland General Electric Company

PGE Exhibit 1203

**Utilities in Peer Group Analysis with PCAMs
for Electric Operations in All States**

		RROE Estimates from DCF Analyses			
		Exhibit 1207	Averages in Exhibit 1209	Exhibit 1210	Type of PCAM
1	Alliant Energy Corporation	9.89%	10.37%	11.02%	Pass-through and Deadband
2	Avista	10.16%	10.51%	10.51%	Sharing and Deadband w/ Sharing
3	Cleco Corporation	13.39%	12.28%	11.01%	Pass-through
4	DPL Inc.	13.81%	13.64%	11.60%	Pass-through
5	El Paso Electric	n/a	n/a	n/a	Pass-through
6	Great Plains Energy	--	--	--	Not available in Missouri
7	IDACORP, Inc.	9.19%	9.41%	9.83%	Sharing
8	NW Natural Gas	n/a	n/a	n/a	Sharing and Pass-through
9	Northwestern Corporation	13.79%	13.17%	12.49%	Pass-through
10	NV Energy	n/a	n/a	n/a	Pass-through
11	OGE Energy Corp.	9.97%	10.03%	10.24%	Pass-through
12	Pinnacle West Capital Corp.	11.67%	11.63%	12.07%	Sharing
13	Pacificorp	n/a	n/a	n/a	none
14	Puget Energy Holdings	n/a	n/a	n/a	Deadband w/ Sharing
15	UniSource Energy Corporation	13.11%	13.40%	10.93%	Pass-through
16	Westar Energy, Inc.	10.56%	11.12%	11.46%	Pass-through
17	Wisconsin Energy Corporation	12.17%	11.43%	10.13%	Pass-through and Deadband
	Constrained Sample Average	11.6%	11.5%	11.0%	--
	Full Sample Average	11.5%	11.5%	11.2%	--

Portland General Electric Company

PGE Exhibit 1204

Evidence Showing Risk Increases as the Market Values of Companies Decrease

	Number of Electric Utilites in this Category	Size Risk Premium	Size Risk Premium for Enterprises the Size of PGE[f/] Compared to Larger Size Companies
1. Evidence from Morningstar[a/]			
Large-Cap Companies[b/]	9	0.02%	1.54%
Mid-Cap Companies[c/]	12	0.90%	0.66%
Low-Cap Companies[d/]	10	1.56%	--

2. Evidence from Zepp paper[f/]

	Risk Premium for Smaller Utilities
Estimated risk premium for smaller utilties compared to larger utilities	0.99%

Notes and Sources:

a/ Data from Table 7-11 of Morningstar, *Ibbotson SBBI 2009 Valuation Yearbook*.

b/ Companies with market capitalization above $7,360 million. Size risk premiums are averages for deciles 1 and 2.

c/ Companies with market capitalization between $1,849 million and $7,360 million included in the Morningstar 2009 study.

d/ Companies with market capitalization between $453 million and $1,849 million included in the Morningstar 2009 study.

e/ Computed as the difference between 1.56% and 0.02% or 1.56% and 0.90%.

f/ 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.*

Portland General Electric Company

PGE Exhibit 1205

Current Annualized Average Dividend Yields for Electric Utilities Sample

		Yield[a/] Based on 3-month Range of Prices	Dividend Forecast[a/] Adjusted for Time Value of Money	3-month[b/] High Stock Price	3-month[b/] Low Stock Price
1	Allegheny Energy, Inc.	2.55%	$0.62	$27.70	$21.84
2	ALLETE, Inc.	5.53%	$1.86	$35.19	$32.23
3	Alliant Energy Corporation	5.94%	$1.61	$28.78	$25.67
4	Ameren Corporation	6.30%	$1.60	$27.27	$23.78
5	American Electric Power Co.	5.52%	$1.71	$32.31	$29.59
6	Avista Corporation	4.91%	$0.97	$21.11	$18.48
7	Cleco Corporation	4.09%	$1.02	$26.26	$23.74
8	CMS Energy Corporation	4.35%	$0.60	$15.14	$12.79
9	DPL Inc.	4.61%	$1.21	$27.86	$24.61
10	DTE Energy Company	5.97%	$2.20	$40.73	$33.75
11	Duke Energy Corporation	6.41%	$1.02	$16.83	$15.04
12	Edison International	3.95%	$1.31	$35.20	$31.42
13	Empire District Electric Co.	7.29%	$1.33	$18.77	$17.78
14	Entergy Corporation	3.96%	$3.12	$81.82	$76.10
15	FPL Group, Inc.	3.98%	$2.08	$56.54	$48.55
16	Great Plains Energy Incorporated	4.88%	$0.86	$18.64	$16.80
17	Hawaiian Electric Industries, Inc.	4.55%	$0.83	$20.20	$16.70
18	IDACORP, Inc.	4.31%	$1.25	$30.28	$27.71
19	MGE Energy, Inc.	4.29%	$1.53	$38.23	$33.41
20	Northwestern Corporation	5.79%	$1.41	$25.80	$23.17
21	OGE Energy Corp.	4.59%	$1.50	$35.13	$30.43
22	PG&E Corporation	4.46%	$1.84	$43.21	$39.53
23	Pinnacle West Capital Corp.	6.59%	$2.18	$35.48	$31.08
24	Portland General Electric	5.54%	$1.08	$20.95	$18.25
25	Progress Energy Inc.	6.74%	$2.58	$39.94	$36.67
26	Southern Company	5.82%	$1.87	$33.78	$30.72
27	TECO Energy, Inc.	5.93%	$0.83	$15.17	$13.06
28	UniSource Energy Corporation	4.11%	$1.21	$31.11	$27.81
29	Westar Energy, Inc.	6.30%	$1.27	$21.56	$18.91
30	Wisconsin Energy Corporation	3.52%	$1.56	$45.89	$42.89
31	Xcel Energy Inc.	5.33%	$1.04	$20.61	$18.53
	Average	5.10%			

Sources and Notes:

a/ Dividend yields (D_1/P_0) are based on Value Line's December 4, 2009 forecasts of dividends (D_1) for the next year corrected for the time value of money.

b/ Prices (P_0) are the highest and lowest prices durng the period September 2009 to November 2009.

Portland General Electric Company

PGE Exhibit 1206

Estimates of Growth Based on Analysts' Forecasts Reported by Value Line, Reuters, Yahoo! Finance and Zacks[a/]

		Value Line[a/]	Zacks[b/]	Yahoo![b/]	Reuters[b/]	Average[c/]
		(a)	(b)	(c)	(d)	(e)
1	Allegheny Energy, Inc.	7.0	16.0	14.0	7.5	11.1
2	ALLETE, Inc.	nmf	4.0	4.0	7.0	5.0
3	Alliant Energy Corporation	4.5	3.0	4.3	4.0	4.0
4	Ameren Corporation	1.0	4.0	3.0	4.0	3.0
5	American Electric Power Co.	3.0	3.3	3.0	4.7	3.5
6	Avista Corporation	6.5	5.0	5.0	4.5	5.3
7	Cleco Corporation	9.5	9.0	9.0	9.7	9.3
8	CMS Energy Corporation	10.0	5.8	5.6	5.8	6.8
9	DPL Inc.	8.5	6.2	7.1	15.0	9.2
10	DTE Energy Company	7.5	4.5	3.0	3.5	4.6
11	Duke Energy Corporation	5.0	4.3	3.6	3.7	4.2
12	Edison International	4.5	5.0	1.0	2.4	3.2
13	Empire District Electric Co.	6.0	n/a	6.0	34.0	15.3
14	Entergy Corporation	6.0	4.7	6.8	8.5	6.5
15	FPL Group, Inc.	8.0	7.8	7.9	7.9	7.9
16	Great Plains Energy Inc.	0.5	5.0	5.0	4.8	3.8
17	Hawaiian Electric Industries, Inc.	7.0	11.3	10.5	3.0	8.0
18	IDACORP, Inc.	4.5	5.0	5.0	5.0	4.9
19	MGE Energy, Inc.	6.0	5.0	5.0	5.0	5.3
20	Northwestern Corporation	9.3	7.7	7.0	n/a	8.0
21	OGE Energy Corp.	4.5	6.0	6.0	5.0	5.4
22	PG&E Corporation	6.5	7.7	7.3	7.0	7.1
23	Pinnacle West Capital Corp.	3.0	8.0	8.0	1.3	5.1
24	Portland General Electric	3.5	6.7	6.8	6.3	5.8
25	Progress Energy Inc.	6.0	4.5	4.5	5.2	5.0
26	Southern Company	4.5	7.6	4.5	5.0	5.4
27	TECO Energy, Inc.	4.5	10.8	9.8	7.7	8.2
28	UniSource Energy Corporation	17.0	5.0	5.0	n/a	9.0
29	Westar Energy, Inc.	4.5	5.0	3.7	3.9	4.3
30	Wisconsin Energy Corporation	8.0	8.3	9.9	8.4	8.7
31	Xcel Energy Inc.	6.5	5.7	7.3	6.4	6.5
	Average	6.1	6.4	6.1	6.8	6.4

Notes and Sources:

a/ Value Line Investment Survey Issue 1 (dated November 27, 2009), the Standard Issue 5 and Small and Mid Cap Issue 5 (dated September 25, 2009) and Issue 11 (dated November 6, 2009).

b/ Sources are analysts' forecasts reported on the Internet on December 18, 2009.

c/ Average of analysts' forecasts including Value Line.

n/a Not available

Portland General Electric Company

PGE Exhibit 1207

Application of the Constant Growth DCF Model

		D_1/P_0[a/]	G[b/]	Equity Cost Estimates
1	Allegheny Energy, Inc.	2.55%	11.13%	13.68%
2	ALLETE, Inc.	5.53%	5.00%	10.53%
3	Alliant Energy Corporation	5.94%	3.95%	9.89%
4	Ameren Corporation	6.30%	3.00%	9.30%
5	American Electric Power Co.	5.52%	3.49%	9.01%
6	Avista Corporation	4.91%	5.25%	10.16%
7	Cleco Corporation	4.09%	9.31%	13.39%
8	CMS Energy Corporation	4.35%	6.80%	11.15%
9	DPL Inc.	4.61%	9.20%	13.81%
10	DTE Energy Company	5.97%	4.63%	10.60%
11	Duke Energy Corporation	6.41%	4.15%	10.56%
12	Edison International	3.95%	3.23%	7.17%
13	Empire District Electric Co.	7.29%	15.33%	22.62%
14	Entergy Corporation	3.96%	6.50%	10.46%
15	FPL Group, Inc.	3.98%	7.89%	11.87%
16	Great Plains Energy Inc.	4.88%	3.84%	8.72%
17	Hawaiian Electric Industries, Inc.	4.55%	7.96%	12.51%
18	IDACORP, Inc.	4.31%	4.88%	9.19%
19	MGE Energy, Inc.	4.29%	5.25%	9.54%
20	Northwestern Corporation	5.79%	8.00%	13.79%
21	OGE Energy Corp.	4.59%	5.38%	9.97%
22	PG&E Corporation	4.46%	7.12%	11.58%
23	Pinnacle West Capital Corp.	6.59%	5.08%	11.67%
24	Portland General Electric	5.54%	5.83%	11.37%
25	Progress Energy Inc.	6.74%	5.05%	11.79%
26	Southern Company	5.82%	5.41%	11.23%
27	TECO Energy, Inc.	5.93%	8.20%	14.12%
28	UniSource Energy Corporation	4.11%	9.00%	13.11%
29	Westar Energy, Inc.	6.30%	4.26%	10.56%
30	Wisconsin Energy Corporation	3.52%	8.66%	12.17%
31	Xcel Energy Inc.	5.33%	6.46%	11.78%
	Column Average	5.1%	6.4%	11.5%

Notes and Sources:

a/ Dividend yields (D_1/P_0) developed in Exhibit 1205.

b/ Growth rates are the average growth rates reported in Exhibit 1206.

Portland General Electric Company

PGE Exhibit 1208

Range of Growth Rates Reported by Four Investor Services[a/]

		Range of Analysts' Forecasts		
		Maximum	Minimum	Mid-point
1	Allegheny Energy, Inc.	16.0%	7.0%	11.5%
2	ALLETE, Inc.	7.0%	4.0%	5.5%
3	Alliant Energy Corporation	4.5%	3.0%	3.8%
4	Ameren Corporation	4.0%	1.0%	2.5%
5	American Electric Power Co.	4.7%	3.0%	3.8%
6	Avista Corporation	6.5%	4.5%	5.5%
7	Cleco Corporation	9.7%	9.0%	9.4%
8	CMS Energy Corporation	10.0%	5.6%	7.8%
9	DPL Inc.	15.0%	6.2%	10.6%
10	DTE Energy Company	7.5%	3.0%	5.3%
11	Duke Energy Corporation	5.0%	3.6%	4.3%
12	Edison International	5.0%	1.0%	3.0%
13	Empire District Electric Co.	34.0%	6.0%	20.0%
14	Entergy Corporation	8.5%	4.7%	6.6%
15	FPL Group, Inc.	8.0%	7.8%	7.9%
16	Great Plains Energy Inc.	5.0%	0.5%	2.8%
17	Hawaiian Electric Industries, Inc.	11.3%	3.0%	7.2%
18	IDACORP, Inc.	5.0%	4.5%	4.8%
19	MGE Energy, Inc.	6.0%	5.0%	5.5%
20	Northwestern Corporation	9.3%	7.0%	8.2%
21	OGE Energy Corp.	6.0%	4.5%	5.3%
22	PG&E Corporation	7.7%	6.5%	7.1%
23	Pinnacle West Capital Corp.	8.0%	1.3%	4.7%
24	Portland General Electric	6.8%	3.5%	5.2%
25	Progress Energy Inc.	6.0%	4.5%	5.3%
26	Southern Company	7.6%	4.5%	6.1%
27	TECO Energy, Inc.	10.8%	4.5%	7.7%
28	UniSource Energy Corporation	17.0%	5.0%	11.0%
29	Westar Energy, Inc.	5.0%	3.7%	4.3%
30	Wisconsin Energy Corporation	9.9%	8.0%	9.0%
31	Xcel Energy Inc.	7.3%	5.7%	6.5%
	Column average	8.8%	4.6%	6.7%

Notes and Sources:

a/ Sources are Value Line, Reuters' consensus estimates, Zacks and Yahoo! Finance. See Exhibit 1206.

Portland General Electric Company

PGE Exhibit 1209

Application of the FERC Multi-period DCF Method

			Low Estimate		High Estimate	
		D_1/P_0	Low Growth	Low Equity Cost Estimate	High Growth	High Equity Cost Estimate
1	Allegheny Energy, Inc.	2.55%	6.61%	9.16%	12.64%	15.19%
2	ALLETE, Inc.	5.53%	4.60%	10.13%	6.61%	12.14%
3	Alliant Energy Corporation	5.94%	3.93%	9.87%	4.93%	10.87%
4	Ameren Corporation	6.30%	2.59%	8.89%	4.60%	10.90%
5	American Electric Power Co.	5.52%	3.93%	9.45%	5.05%	10.57%
6	Avista Corporation	4.91%	4.93%	9.84%	6.27%	11.18%
7	Cleco Corporation	4.09%	7.95%	12.04%	8.43%	12.52%
8	CMS Energy Corporation	4.35%	5.67%	10.02%	8.62%	12.97%
9	DPL Inc.	4.61%	6.07%	10.69%	11.97%	16.58%
10	DTE Energy Company	5.97%	3.93%	9.90%	6.94%	12.92%
11	Duke Energy Corporation	6.41%	4.33%	10.75%	5.27%	11.68%
12	Edison International	3.95%	2.61%	6.56% _b/	5.27%	9.22%
13	Empire District Electric Co.	7.29%	5.94%	13.23%	24.70%	31.99%
14	Entergy Corporation	3.96%	5.07%	9.02%	7.63%	11.58%
15	FPL Group, Inc.	3.98%	7.15%	11.13%	7.28%	11.26%
16	Great Plains Energy Inc.	4.88%	2.25%	7.14% _b/	5.27%	10.15%
17	Hawaiian Electric Industries, Inc.	4.55%	3.93%	8.48%	9.49%	14.04%
18	IDACORP, Inc.	4.31%	4.93%	9.25%	5.27%	9.58%
19	MGE Energy, Inc.	4.29%	5.27%	9.56%	5.94%	10.23%
20	Northwestern Corporation	5.79%	6.61%	12.40%	8.15%	13.94%
21	OGE Energy Corp.	4.59%	4.93%	9.53%	5.94%	10.53%
22	PG&E Corporation	4.46%	6.27%	10.73%	7.08%	11.54%
23	Pinnacle West Capital Corp.	6.59%	2.81%	9.40%	7.28%	13.87%
24	Portland General Electric	5.54%	4.26%	9.81%	6.48%	12.02%
25	Progress Energy Inc.	6.74%	4.93%	11.68%	5.94%	12.68%
26	Southern Company	5.82%	4.93%	10.75%	7.01%	12.83%
27	TECO Energy, Inc.	5.93%	4.93%	10.86%	9.16%	15.08%
28	UniSource Energy Corporation	4.11%	5.27%	9.38%	13.31%	17.42%
29	Westar Energy, Inc.	6.30%	4.38%	10.67%	5.27%	11.57%
30	Wisconsin Energy Corporation	3.52%	7.28%	10.80%	8.55%	12.07%
31	Xcel Energy Inc.	5.33%	5.74%	11.07%	6.80%	12.12%
	Average			10.1%		12.9%
	Mid-point				11.5%	

Sources and Notes:

a/ Use FERC method of assigning a weight of two-thirds to average EPS growth rates reported in Exhibit 1208 and one-third to a forecast of future GPD growth of 5.8%.

b/ Low equity cost estimate equal to or below the expected cost of investment grade debt of 7.14%. See Exhibit 1211. To be conservative, these estimates were not removed from data.

Portland General Electric Company

PGE Exhibit 1210

Alternative Multi-Stage DCF Growth Analysis

		Internal Rate of Return		First Year Dividend D_1[a/]	Stage 1[b/]		Stage 2 and 3[c,d/]		
		Return	P_{2009}	D_{2010}	D_{2011}	D_{2015}	D_{2016}	$(P+D)_{2025}$	P_{2025}[d/]
1	Allegheny Energy, Inc.	12.95%	-$24.77	$1.86	$1.95	$2.38	$2.50	$63.95	$59.91
2	ALLETE, Inc.	9.99%	-$33.71	$1.61	$1.68	$1.96	$2.04	$83.74	$80.56
3	Alliant Energy Corporation	11.02%	-$27.23	$1.61	$1.68	$1.96	$2.04	$67.81	$64.63
4	Ameren Corporation	10.98%	-$25.53	$1.60	$1.65	$1.86	$1.92	$62.20	$59.30
5	American Electric Power Co.	10.49%	-$30.95	$1.71	$1.76	$2.02	$2.10	$76.25	$73.02
6	Avista Corporation	10.51%	-$19.80	$0.97	$1.02	$1.25	$1.32	$50.54	$48.39
7	Cleco Corporation	11.01%	-$25.00	$1.02	$1.11	$1.59	$1.73	$69.23	$65.99
8	CMS Energy Corporation	10.45%	-$13.97	$0.60	$0.64	$0.84	$0.89	$36.67	$35.14
9	DPL Inc.	11.60%	-$26.24	$1.21	$1.32	$1.87	$2.04	$73.33	$69.53
10	DTE Energy Company	11.27%	-$37.24	$2.20	$2.31	$2.76	$2.89	$94.28	$89.65
11	Duke Energy Corporation	11.53%	-$15.94	$1.02	$1.06	$1.25	$1.30	$39.94	$37.89
12	Edison International	9.05%	-$33.31	$1.31	$1.35	$1.54	$1.59	$81.62	$79.20
13	Empire District Electric Co.	18.00%	-$18.28	$1.33	$1.53	$2.72	$3.11	$68.52	$61.43
14	Entergy Corporation	9.97%	-$78.96	$3.12	$3.32	$4.27	$4.55	$205.13	$197.39
15	FPL Group, Inc.	10.41%	-$52.55	$2.08	$2.24	$3.04	$3.27	$140.53	$134.69
16	Great Plains Energy Inc.	10.04%	-$17.72	$0.86	$0.90	$1.04	$1.08	$43.93	$42.24
17	Hawaiian Electric	11.05%	-$18.45	$0.83	$0.90	$1.22	$1.31	$49.90	$47.55
18	IDACORP, Inc.	9.83%	-$29.00	$1.25	$1.31	$1.58	$1.66	$73.20	$70.52
19	MGE Energy, Inc.	9.91%	-$35.82	$1.53	$1.61	$1.97	$2.08	$91.06	$87.67
20	Northwestern Corporation	12.49%	-$24.49	$1.41	$1.53	$2.08	$2.24	$67.93	$63.92
21	OGE Energy Corp.	10.24%	-$32.78	$1.50	$1.58	$1.95	$2.05	$83.72	$80.36
22	PG&E Corporation	10.69%	-$41.37	$1.84	$1.97	$2.60	$2.78	$109.62	$104.79
23	Pinnacle West Capital Corp.	12.07%	-$33.28	$2.18	$2.29	$2.80	$2.94	$85.56	$80.79
24	Portland General Electric	11.34%	-$19.60	$1.08	$1.14	$1.44	$1.52	$50.98	$48.45
25	Progress Energy Inc.	12.22%	-$38.31	$2.58	$2.71	$3.30	$3.47	$98.50	$92.88
26	Southern Company	11.46%	-$32.25	$1.87	$1.97	$2.44	$2.57	$83.20	$78.99
27	TECO Energy, Inc.	12.69%	-$14.12	$0.83	$0.90	$1.23	$1.33	$39.35	$36.95
28	UniSource Energy Corporation	10.93%	-$29.46	$1.21	$1.31	$1.86	$2.02	$81.02	$77.29
29	Westar Energy, Inc.	11.46%	-$20.24	$1.27	$1.32	$1.56	$1.63	$50.84	$48.27
30	Wisconsin Energy Corp	10.13%	-$44.39	$1.56	$1.69	$2.36	$2.56	$119.62	$114.93
31	Xcel Energy Inc.	11.37%	-$19.57	$1.04	$1.11	$1.42	$1.51	$51.60	$49.03
	Average	11.2%							

Notes and Sources:

a/ Value Line forecast of DPS growth adjusted for the time value of money. See Exhibit 1205.

b/ Mid-point of range of analysts' forecasts from Exhibit 1208.

c/ Growth based on gradual transition from analysts' forecasts of growth to expected long-term average GDP growth of 5.8%.

d/ Price received at end of stage 2.

Portland General Electric Company

PGE Exhibit 1211

Forecasts of Treasury and Baa Corporate Bond Rates

	2011	2012	2013	Average
Long-term Treasury Rates				
Blue Chip Consensus Forecasts[a/]	5.10%	5.50%	5.80%	
Value Line[b/]	5.00%	5.10%	5.30%	
Global Insight[c/]	4.59%	4.89%	5.18%	
Average	4.90%	5.16%	5.43%	5.16%
Baa Corporate Bonds Rates				
Blue Chip Consensus Forecasts[a/]	7.00%	7.40%	7.60%	
Value Line[b/]	n/a	n/a	n/a	
Global Insight[c/]	6.59%	7.00%	7.22%	
Average	6.80%	7.20%	7.41%	7.14%

Sources and Notes:
a/ December 2009 Blue Chip long-term consensus forecasts.
b/ Value Line Quarterly forecasts dated November 27, 2009.
c/ December 2009 IHS Global Insight forecasts.
n/a Not available

Portland General Electric Company

PGE Exhibit 1212

Risk Premium Analysis:
Method Used by Department of Ratepayer Advocates of the California PUC[a/] with Data for Prior Oregon PUC Sample[b/]
1999 to 2008

	Return on Equity[b/]	Baa Corporate Bond Rates[c/]	Average Annual Risk Premiums
1999	11.46%	7.88%	3.58%
2000	10.92%	8.37%	2.55%
2001	11.59%	7.95%	3.64%
2002	10.69%	7.80%	2.89%
2003	10.96%	6.76%	4.20%
2004	10.40%	6.39%	4.01%
2005	10.49%	6.06%	4.43%
2006	10.97%	6.48%	4.49%
2007	10.96%	6.48%	4.48%
2008	10.94%	7.44%	3.50%
	10-Year Average	7.16%	3.78%
	5-year Average	6.57%	4.18%
	Expected Baa Rate for 2011-2013[d/]		7.14%
	Projected Returns on Equity for Sample		
	10-Year Average		10.9%
	5-Year Average		11.3%
	Indicated Average Cost of Equity for PGE		11.3%

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.

b/ Average of earned ROEs for the surviving utilities relied upon by the Oregon PUC to determine equity costs for electric utilities sample in UE-180.

c/ As reported by the Federal Reserve.

d/ Source is Exhibit 1211.

Portland General Electric Company

PGE Exhibit 1213

Risk Premium Analysis Based on Holding Period Returns for Moody's Electric Utilities Sample as Updated, 1950 to 2008

	Baa Corporate Bond Rate[a/]	Year-end Price Index[b/]	Annual Average Dividend[b/]	Index Gain/Loss	Dividend Yield	Total Return	Risk Premium
1950	3.20%	$30.81					
1951	3.61%	$33.85	$1.88	9.87%	6.10%	15.97%	12.77%
1952	3.51%	$37.85	$1.91	11.82%	5.64%	17.46%	13.85%
1953	3.74%	$39.61	$2.01	4.65%	5.31%	9.96%	6.45%
1954	3.45%	$47.56	$2.13	20.07%	5.38%	25.45%	21.71%
1955	3.62%	$49.35	$2.21	3.76%	4.65%	8.41%	4.96%
1956	4.37%	$48.96	$2.32	-0.79%	4.70%	3.91%	0.29%
1957	5.03%	$50.30	$2.43	2.74%	4.96%	7.70%	3.33%
1958	4.85%	$66.37	$2.50	31.95%	4.97%	36.92%	31.89%
1959	5.28%	$65.77	$2.61	-0.90%	3.93%	3.03%	-1.82%
1960	5.10%	$76.82	$2.68	16.80%	4.07%	20.88%	15.60%
1961	5.10%	$99.32	$2.81	29.29%	3.66%	32.95%	27.85%
1962	4.92%	$96.49	$2.97	-2.85%	2.99%	0.14%	-4.96%
1963	4.85%	$102.31	$3.21	6.03%	3.33%	9.36%	4.44%
1964	4.81%	$115.54	$3.43	12.93%	3.35%	16.28%	11.43%
1965	5.02%	$114.86	$3.86	-0.59%	3.34%	2.75%	-2.06%
1966	6.18%	$105.99	$4.11	-7.72%	3.58%	-4.14%	-9.16%
1967	6.93%	$98.19	$4.34	-7.36%	4.09%	-3.26%	-9.44%
1968	7.23%	$104.04	$4.50	5.96%	4.58%	10.54%	3.61%
1969	8.65%	$84.62	$4.61	-18.67%	4.43%	-14.23%	-21.46%
1970	9.12%	$88.59	$4.70	4.69%	5.55%	10.25%	1.60%
1971	8.38%	$85.56	$4.77	-3.42%	5.38%	1.96%	-7.16%
1972	7.93%	$83.61	$4.87	-2.28%	5.69%	3.41%	-4.97%
1973	8.48%	$60.87	$5.01	-27.20%	5.99%	-21.21%	-29.14%
1974	10.63%	$41.17	$4.83	-32.36%	7.93%	-24.43%	-32.91%
1975	10.56%	$55.66	$4.97	35.20%	12.07%	47.27%	36.64%
1976	9.12%	$66.29	$5.18	19.10%	9.31%	28.40%	17.84%
1977	8.99%	$68.19	$5.54	2.87%	8.36%	11.22%	2.10%
1978	9.94%	$59.75	$5.81	-12.38%	8.52%	-3.86%	-12.85%
1979	12.06%	$56.41	$6.22	-5.59%	10.41%	4.82%	-5.12%
1980	14.64%	$54.42	$6.58	-3.53%	11.66%	8.14%	-3.92%
1981	16.55%	$57.20	$6.99	5.11%	12.84%	17.95%	3.31%
1982	14.14%	$70.26	$7.43	22.83%	12.99%	35.82%	19.27%
1983	13.75%	$72.03	$7.87	2.52%	11.20%	13.72%	-0.42%
1984	13.40%	$80.16	$8.26	11.29%	11.47%	22.75%	9.00%
1985	11.58%	$94.98	$8.61	18.49%	10.74%	29.23%	15.83%
1986	9.97%	$113.66	$8.89	19.67%	9.36%	29.03%	17.45%
1987	11.29%	$94.24	$9.12	-17.09%	8.02%	-9.06%	-19.03%
1988	10.65%	$100.94	$8.87	7.11%	9.41%	16.52%	5.23%
1989	9.82%	$122.52	$8.82	21.38%	8.74%	30.12%	19.47%
1990	10.43%	$117.77	$8.79	-3.88%	7.17%	3.30%	-6.52%
1991	9.26%	$144.02	$8.95	22.29%	7.60%	29.89%	19.46%
1992	8.81%	$141.06	$9.05	-2.06%	6.28%	4.23%	-5.03%
1993	7.69%	$146.70	$8.99	4.00%	6.37%	10.37%	1.56%
1994	9.10%	$115.50	$8.96	-21.27%	6.11%	-15.16%	-22.85%
1995	7.49%	$142.90	$9.02	23.72%	7.81%	31.53%	22.43%

	Baa Corporate Bond Rate[a/]	Year-end Price Index[b/]	Annual Average Dividend[b/]	Index Gain/Loss	Dividend Yield	Total Return	Risk Premium
1996	7.89%	$136.00	$9.06	-4.83%	6.34%	1.51%	-5.98%
1997	7.32%	$155.73	$9.06	14.51%	6.66%	21.17%	13.28%
1998	7.23%	$181.84	$7.83	16.77%	5.03%	21.79%	14.47%
1999	8.19%	$137.30	$8.10	-24.49%	4.45%	-20.04%	-27.27%
2000	8.02%	$227.09	$8.27	65.40%	6.02%	71.42%	63.23%
2001	8.05%	$210.41	$7.28	-7.35%	3.20%	-4.14%	-12.16%
2002	7.45%	$184.46	$7.52	-12.33%	3.57%	-8.76%	-16.81%
2003	6.60%	$194.36	$7.13	5.37%	3.87%	9.23%	1.78%
2004	6.15%	$231.72	$7.22	19.22%	3.72%	22.93%	16.33%
2005	6.32%	$250.52	$7.59	8.12%	3.27%	11.39%	5.24%
2006	6.22%	$287.25	$7.79	14.66%	3.11%	17.77%	11.45%
2007	6.65%	$318.76	$8.13	10.97%	2.83%	13.80%	7.58%
2008	--	$211.71	$8.57	-33.58%	2.69%	-30.90%	-37.55%

	Updated Study	Original Study
Average Baa rate	7.9%	8.1%
Unadjusted risk premium	3.2%	4.2%
Expected Baa bond rate	7.1%	7.1%
Adjusted risk premium[c/]	3.6%	4.6%
Estimated cost of equity for benchmark s	10.7%	11.8%

Notes and Sources:

a/ Federal Reserve data. Monthly rates for December of the indicated year.
b/ Mergent, Moody's 2001 Public Utility Manual with updates for 2001-2008.
c/ As explained in testimony, adjustment assumes equity costs change by 50% as much as interest rates.

Portland General Electric Company

PGE Exhibit 1214

Risk Premiums Deternined by Relationship Between Authorized ROEs and Baa Corporate Bond Rates[a/] During the Period 1985-2008

Regression Output:

Constant (A_0)		0.0652
Std Err of Y Est		0.0072
R Squared		58.2%
No. of Observations		491
Degrees of Freedom		489
X Coefficient (A_1)	-0.3931	
Std Err of Coef.	0.0151	
t-statistic	-26.0772	

Equity Cost Estimate for Typical Electric Utility		Predicted Risk Premium		Expected Baa Bond Rate[b/]
10.9%	=	3.72%	+	7.14%

Formula: Risk Premium = A_0 + (A_1 x Baa bond Rate)[c/]

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 decisions reported by Regulatory Research Associates for 1999-2008.

_b/ Average of forecasts for 2011 to 2013 reported in Exhibit 1211.

_c/ 6-month lag between order dates and Baa bond rates adopted.

Portland General Electric Company

PGE Exhibit 1215

Earned and Authorized ROEs for Electric Utilities Sample

		Recent Earned ROEs	Earned ROE As An Indicator Of Required ROE	Authorized ROEs
1	Allegheny Energy, Inc.	10.12%	10.12%	10.46%
2	ALLETE, Inc.	8.71%	8.71%	10.74%
3	Alliant Energy Corporation	4.55%	_b/	11.02%
4	Ameren Corporation	7.93%	7.93%	10.64%
5	American Electric Power Co.	10.74%	10.74%	10.71%
6	Avista Corporation	8.19%	8.19%	10.40%
7	Cleco Corporation	10.73%	10.73%	10.70%
8	CMS Energy Corporation	10.11%	10.11%	10.93%
9	DPL Inc.	24.78%	24.78%	11.00%
10	DTE Energy Company	9.30%	9.30%	11.00%
11	Duke Energy Corporation	4.65%	_b/	10.89%
12	Edison International	9.15%	9.15%	10.71%
13	Empire District Electric Co.	7.45%	7.45%	10.80%
14	Entergy Corporation	13.40%	13.40%	10.76%
15	FPL Group, Inc.	14.27%	14.27%	11.75%
16	Great Plains Energy Incorporated	5.22%	_b/	10.45%
17	Hawaiian Electric Industries, Inc.	11.64%	11.64%	10.82%
18	IDACORP, Inc.	8.20%	8.20%	10.50%
19	MGE Energy, Inc.	10.20%	10.20%	10.80%
20	Northwestern Corporation	9.03%	9.03%	11.11%
21	OGE Energy Corp.	12.64%	12.64%	10.13%
22	PG&E Corporation	13.57%	13.57%	11.35%
23	Pinnacle West Capital Corp.	1.68%	_b/	10.75%
24	Portland General Electric	7.36%	7.36%	10.00%
25	Progress Energy Inc.	8.53%	8.53%	12.42%
26	Southern Company	11.29%	11.29%	11.93%
27	TECO Energy, Inc.	10.49%	10.49%	11.00%
28	UniSource Energy Corporation	16.69%	16.69%	10.13%
29	Westar Energy, Inc.	7.86%	7.86%	10.00%
30	Wisconsin Energy Corporation	10.77%	10.77%	10.75%
31	Xcel Energy Inc.	9.58%	9.58%	10.76%
	Average	10.0%	10.8%	10.8%

Notes and Sources

a/ AUS Utility Reports, December 2009.

b/ Eliminate any ROE below expected cost of investment grade debt.

Portland General Electric Company

PGE Exhibit 1216

Summary Table: Estimated Costs of Equity for Benchmark Samples and PGE

	Estimated Equity Costs for Benchmark Utilities			Estimated Equity Costs for PGE[n/]		
DCF Analyses						
DCF analysis -- Table 7		11.5%			11.7%	
DCF analysis -- Table 9		11.5%			11.7%	
DCF analysis -- Table 10		11.2%			11.4%	
Average of DCF Estimates		11.4%			11.6%	
Risk Premium analyses						
Risk premium -- Table 12	10.9%	to	11.3%	11.1%	to	11.5%
Risk Premium -- Table 13	10.7%	to	11.8%	10.9%	to	12.0%
Risk premium -- Table 14		10.9%			11.1%	
Average of RP Estimates		11.1%			11.3%	
Earned & Authorized ROEs		10.8%			11.0%	
Range of Equity Cost Estimates	10.7%	to	11.8%	10.9%	to	12.0%
Average of Equity Cost Estimates		11.2%			11.4%	
Recommened Minimum ROE for PGE					11.0%	

Note:
n/ Equity Cost estimates include a 20 basis point risk premium for PGE.

Table of Contents

I. Introduction and Background

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

A. My name is Steven M. Fetter. I am President of Regulation UnFettered. My business address is 1489 W. Warm Springs Rd., Suite 110, Henderson, Nevada 89014.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of Portland General Electric Company ("PGE" or the "Company").

Q. By whom are you employed and in what capacity?

A. I am President of Regulation UnFettered, a utility advisory firm I started in April 2002. Prior to that, I was employed by Fitch, Inc. ("Fitch"), a credit rating agency based in New York and London. Prior to that, I served as Chairman of the Michigan Public Service Commission ("Michigan PSC").

Q. What is your educational background?

A. I graduated with high honors from the University of Michigan with an A.B. in Communications in 1974. I graduated from the University of Michigan Law School with a J.D. in 1979.

Q. Please briefly describe your role as president of Regulation Unfettered.

A. I formed a utility advisory firm to use my financial, regulatory, legislative, and legal expertise to aid the deliberations of regulators, legislative bodies, and the courts, and to assist them in evaluating regulatory issues. My clients include investor-owned and municipal electric, natural gas and water utilities, state public utility commissions and consumer advocates, non-utility energy suppliers, international financial services and consulting firms, and investors.

Q. What was your role during your employment with Fitch?

A. I was Group Head and Managing Director of the Global Power Group within Fitch. In that role, I served as group manager of the combined 18-person New York and Chicago utility team. I was originally hired to interpret the impact of regulatory and legislative developments on utility credit ratings, a responsibility I continued to have throughout my tenure at the rating agency. In April 2002, I left Fitch to start Regulation UnFettered.

Q. How long were you employed by Fitch?

A. I was employed by Fitch from October 1993 until April 2002. In addition, Fitch retained me as a consultant for a period of approximately six months shortly after I resigned.

Q. How does your experience relate to your testimony in this proceeding?

A. My experience as a Commissioner on the Michigan PSC and my subsequent professional experience analyzing the U.S. electric and natural gas sectors – in jurisdictions involved in restructuring activity as well as those still following a traditional regulated path – have given me solid insight into the importance of a regulator's role in setting rates and also in determining appropriate terms and conditions of service for regulated utilities. These are among the factors that enter into the process of utility credit analysis and formulation of individual company credit ratings. It is undeniable that a utility's credit ratings significantly affect the ability of a utility to raise capital on a timely basis and upon reasonable terms.

Q. Have you previously given testimony before regulatory and legislative bodies?

A. Yes. Since 1990, I have testified on numerous occasions before the U.S. Senate, the U.S. House of Representatives, the Federal Energy Regulatory Commission, and various state legislative and regulatory bodies on the subjects of credit risk within the utility sector, electric and natural gas utility restructuring, fuel and other energy cost adjustment mechanisms, construction work in progress and other interim rate recovery structures, utility securitization bonds, and nuclear energy. With regard to fuel and purchased power cost recovery mechanisms ("PCAMs"), I have previously testified on that issue on behalf of PSI Energy in Cause No. 42200 before the Indiana Utility Regulatory Commission, Arizona Public Service Company in Docket Nos. E-01345A-03-0437 and E-01345A-06-0009 before the Arizona Corporation Commission, Entergy Arkansas, Inc. in Docket No. 05-116-U/06-055-U before the Arkansas Public Service Commission, Aquila, Inc. in Case No. ER-2007-0004 before the Missouri Public Service Commission, and Public Service Company of New Mexico in Case No. 07-00077-UT before the New Mexico Public Regulation Commission. I also testified before the Indiana Legislature in 2007 on the general subject of adjustment or tracking mechanisms, not only PCAMs but also trackers targeting costs related to environmental compliance, new clean coal generation, DSM & energy efficiency, and renewable energy.

My full educational and professional background is presented in PGE Exhibit 1301.

II. Executive Summary

Q. What is the purpose of your direct testimony?

A. I believe that reinstitution of a PCAM for PGE by the Oregon Public Utility Commission (“OPUC” or “Commission”) in 2007 represented a positive policy step. However, based upon my background as a state regulator and bond rater, I do not believe that the current framework of that PCAM achieves what I believe should be the goal of utility regulation: timely recovery of all costs prudently expended by a regulated utility in order to provide reliable service to customers at a reasonable cost. Accordingly, I will provide testimony here on why the current framework of PGE’s PCAM differs from mainstream regulatory practice, and thus places the Company at a competitive disadvantage in attracting capital in the current economic environment. When utility investors choose to take their funds to jurisdictions that provide greater certainty of timely recovery of prudent expenditures, the cost of capital for regulated utilities in Oregon goes up.

In explaining why I believe that modification of PGE’s PCAM by the Commission would be consistent with the public interest, I will address my positive experiences working with PCAMs as a regulator in Michigan. I will also discuss the acceptance that the concept of recovery of actual prudent fuel and power supply costs has received in a large majority of states across the United States.

III. Current Economy

Q. Would you provide your thoughts about the recent economic recession faced by the U.S. utility industry?

A. Yes. With the capital markets having experienced a worldwide financial crisis and subsequent severe economic recession, I believe it is important for regulators to factor into their decision-making the particular negative stresses that a regulated utility with credit ratings in the 'BBB' category currently faces. The U.S. stock market experienced its third-worst year in more than a century in 2008, with the S&P 500 and the Dow Jones Industrial Average down 38.5% and 33.8%, respectively. No fewer than fifteen U.S. banks failed in 2008, including the well-publicized bankruptcy of Lehman Brothers on September 15, 2008, the largest bankruptcy in U.S. history. While the capital markets have stabilized to a degree during the past twelve months, substantial concerns remain due to continuing high unemployment, a rapidly growing federal deficit, and fear that the bursting housing bubble has not yet reached full collapse, with commercial real estate seemingly at risk as weakness in the U.S. economy continues during the next couple of years. This uncertainty means that there likely will be less capital available for companies seeking debt and equity financing – and, unlike the broader corporate industrial sector which can delay capital investment in times of duress, electric utilities have an obligation to serve and thus carry a public responsibility to expend capital when needed to ensure safe and reliable service to customers. As Moody's reported in a January 16, 2009, report entitled, "Near-term Bank Credit Facility Renewals To Be More Challenging For U.S. Investor-Owned Electric and Gas Utilities":

> "Dramatic changes in the financial markets during 2008 have materially changed the banking environment for utilities going forward, which will make upcoming credit facility renewals significantly more challenging. Those banks that do remain will be constrained in both their ability and inclination to provide traditional credit, especially at the relatively low pricing levels and on the liberal terms and conditions that prevailed prior to mid-2008."

Q. Have other industry leaders offered similar cautions?

A. Yes. During the January 13, 2009, Federal Energy Regulatory Commission ("FERC") Technical Conference on Credit and Capital Issues Affecting the Electric Power Industry, regulators, industry representatives, and banks all agreed that the financial crisis is having a more dramatic impact on lower rated utilities. W. Paul Bowers, the Executive Vice President and Chief Financial Officer of Southern Company, noted that although the financial crisis has led to increases in debt and equity risk premiums for all utilities, these increases have been more consistently applied to utilities that do not hold high credit ratings, resulting in significantly higher cost of debt capital for 'BBB' category utilities as compared to 'A' rated utilities.[1] Mr. Bowers's views were corroborated by Anthony Ianno, Managing Director and Head of Energy and Utilities Global Risk Capital Markets at Morgan Stanley, with data that showed that investment in 'BBB' rated utilities dropped approximately 13% in the period after the Lehman Brothers bankruptcy, while investment in 'A' rated utilities rose by the same margin.[2] Such data clearly shows that, in the wake of the financial crisis, investor interest has been increasingly directed toward less risky 'A' rated utilities. As Chairman Garry Brown of the New York Public Service Commission ("NYPSC") noted at the FERC conference, "there

[1] Statement of W. Paul Bowers at Federal Energy Regulatory Commission Technical Conference on Credit and Capital Issues Affecting the Electric Power Industry, Docket No. AD09-2-000, January 13, 2009.
[2] Statement of Anthony Ianno at Federal Energy Regulatory Commission Technical Conference on Credit and Capital Issues Affecting the Electric Power Industry, Docket No. AD09-2-000, January 13, 2009.

is a clear relationship between a utility's bond rating and its ability to borrow at a reasonable cost, particularly in times of economic distress as we are now facing."[3]

Given the Company's significant ongoing capital program and 'BBB' category ratings status, sustained regulatory support is imperative for the Company to be able to access adequate capital at reasonable costs for the ultimate benefit of its customers. As I alluded to earlier, electric utilities do not possess the strategic option of substantially cutting back their operations during difficult economic times. Utilities must provide safe, efficient, and reliable service to their customers, notwithstanding dysfunction within the financial markets. The electric utility sector is one of the most capital-intensive sectors in the country, and utilities must continue to make significant capital expenditures to maintain reliability, replace aging infrastructure, and meet longer-term load growth requirements. As NYPSC Chairman Brown further noted at the FERC Conference, "Large capital programs make it very important that electric utilities continue to have access to the financial markets, and regulatory policies should support utilities' ability to raise capital."

[3] Statement of Garry Brown at Federal Energy Regulatory Commission Technical Conference on Credit and Capital Issues Affecting the Electric Power Industry, Docket No. AD09-2-000, January 13, 2009.

IV. Credit Ratings

Q. To place PGE's current ratings status into perspective, could you provide a brief overview of the credit rating process?

A. Yes. Credit ratings reflect a credit rating agency's independent judgment of the general creditworthiness of an obligor or the creditworthiness of a specific debt instrument. While credit ratings are important to both debt and equity investors for a variety of reasons, their most important purpose is to communicate to investors the financial strength of a company or the underlying credit quality of a particular debt security issued by that company. Credit rating determinations are made through a committee process involving individuals with knowledge of a company, its industry, and its regulatory environment. Corporate rating designations of S&P and Fitch basically have "AA", "A" and "BBB" category ratings within the investment-grade ratings sphere, with "BBB-" as the lowest investment-grade rating and "BB+" as the highest non-investment-grade rating. Comparable rating designations of Moody's at the investment-grade dividing line are "Baa3" and "Ba1", respectively.

Corporate credit ratings analysis considers both qualitative and quantitative factors to assess the financial and business risks of fixed-income issuers. A credit rating is an indication of an issuer's ability to service its debt, both principal and interest, on a timely basis. It also at times incorporates some consideration of ultimate recovery of investment in case of default or insolvency. Ratings can also be used by contractual counterparties to gauge both the short-term and longer-term health and viability of a company.

Q. Can you provide a brief discussion on why credit ratings are important for regulated utilities and their customers?

A. Yes. It is a well-established fact that a utility's credit ratings have a significant impact as to whether that utility will be able to raise capital on a timely basis and upon reasonable terms. As respected economist Charles F. Phillips stated in his treatise on utility regulation:

> Bond ratings are important for at least four reasons: (1) they are used by investors in determining the quality of debt investment; (2) they are used in determining the breadth of the market, since some large institutional investors are prohibited from investing in the lower grades; (3) **they determine, in part, the cost of new debt, since both the interest charges on new debt and the degree of difficulty in marketing new issues tend to rise as the rating decreases**; and (4) they have an indirect bearing on the status of a utility's stock and on its acceptance in the market.[4] [Emphasis supplied.]

Thus, the lower a regulated utility's credit rating, the more the utility will have to pay to raise funds from debt and equity investors to carry out its capital-intensive operations. In turn, the ratemaking process factors the cost of capital for both debt and equity into the rates that consumers are required to pay. Therefore, a utility with strong credit ratings is not only able to access the capital markets on a timely basis at reasonable rates, it also is able to share the benefit from those attractive interest rate levels with customers through the rate-setting process. Access to the capital markets is especially important for a company like PGE, which is planning to expend significant levels of capital in order to take steps to ensure continuing reliability of service to customers.

Q. Please describe the qualitative factors used by the rating agencies.

---

[4] Phillips, Charles F., Jr., <u>The Regulation of Public Utilities</u>, Arlington, Virginia: Public Utilities Reports, Inc., 1993, at p. 250. See also Public Utilities Reports Guide: "Finance," Public Utilities Reports, Inc., 2004 at pp. 6-7 ("Generally, the higher the rating of the bond, the better the access to capital markets and the lower the interest to be paid.").

A. The most important qualitative factors include regulation, management and business strategy, and access to energy, gas and fuel supply with recovery of associated costs.[5]

Q. Please explain your thoughts on the importance of regulation within the credit ratings process.

A. Regulation is a key factor in assessing the credit profile of a utility because a state public utility commission determines rate levels (recoverable expenses including depreciation and operations and maintenance, fuel cost recovery, and return on investment) and the terms and conditions of service.

Since the announcement of California's restructuring plan in 1994, regulation has become an even more important factor as the nature of a utility's responsibilities in providing energy services to customers has undergone dramatic change. In some states, industry restructuring was the result of plans formulated by the state legislature. In other states, the regulators, rather than the legislators, have determined the nature and pace of restructuring, or whether it would occur at all.

This situation thus affects utility investors' decisions because, before major investors will be willing to put forward substantial sums of money, they will want to gain comfort that regulators understand the economic requirements and the financial and operational risks of a rapidly changing industry and will make fair decisions that are significantly predictable.

---

[5] In their analysis, the rating agencies use quantitative factors hand-in-hand with the qualitative factors noted above. S&P has highlighted the three key ratios it most relies upon in its utility ratings assessments: Funds from Operations Interest Coverage; Funds from Operations / Total Debt; and Total Debt / Total Capital. (*See* S&P Research: "U.S. Utilities Ratings Analysis Now Portrayed in the S&P Corporate Ratings Matrix," November 30, 2007.) Moody's tracks use of these measures and adds "Cash from Operations minus dividends / Debt" as a fourth key measure. (*See* Moody's Research: "Rating Methodology: Regulated Electric and Gas Utilities," August 2009.) With the subject of my testimony being PCAMs, I focus the bulk of my discussion on the qualitative factors of regulation and recovery of fuel and power supply costs.

For these reasons, rating agencies look for the consistent application of sound economic regulatory principles by the commissions. If a regulatory body were to encourage a company to make investments based upon an expectation of the opportunity to earn a reasonable return – or, as discussed here, to receive full recovery for prudently incurred expenditures – and then did not apply regulatory principles in a manner consistent with such expectations, investor interest in providing funds to such utility would decline, debt ratings would likely suffer, and the utility's cost of capital would increase.

Q. Have the recent financial and operational challenges facing all utility managements increased the focus on the actions of utility regulators by the financial community?

A. Yes, without a doubt. Events like the California restructuring debacle and Hurricanes Katrina and Rita have tested the financial standing of the utility sector like never before. With the extreme turmoil in the financial markets during the past year, we appear to have come to another "never before" moment. Liquidity, or access to cash when needed, has always been a major issue for regulated utilities, but it has leaped to the forefront of utility financial and operational concerns and has driven structural decisions on the part of utility executives.[6]

Thus, while "Regulation" has always garnered the attention of Wall Street, years ago it seemed to be a focus only during the days leading up to a commission's rate case decision. This began to change around the time that Fitch hired me in 1993 to serve in the role of regulatory analyst and to assess regulatory, legislative and

[6] See, for example, "Utilities' Plans Hit by Credit Markets," Wall Street Journal, October 1, 2008 ("Disruptions in credit markets are jolting the capital-hungry utility sector, forcing companies to delay new borrowing or to come up with different – and often more costly – ways of raising cash.").

political factors that could affect a utility's financial strength. When California announced its ill-fated restructuring plan in 1994, the entire financial community took much greater notice of regulators and how they carried out their responsibilities, not only with regard to rate-setting, but even more importantly the manner in which they undertook to change the way the entire utility industry had operated for over 100 years. And of course the recent stresses within the credit markets with their huge financial repercussions have made regulatory decision-making and policies even more important.

Q. Do the rating agencies agree that utility regulators and their decision-making have increased in importance?

A. Yes. S&P highlighted the increasing importance of regulation to the financial community in a November 26, 2008 report entitled "Key Credit Factors: Business and Financial Risks in the Investor-Owned Utilities Industry":

> Regulation is the most critical aspect that underlies regulated integrated utilities' creditworthiness. Regulatory decisions can profoundly affect financial performance. Our assessment of the regulatory environments in which a utility operates is guided by certain principles, most prominently consistency and predictability, as well as efficiency and timeliness. For a regulatory process to be considered supportive of credit quality, it must limit uncertainty in the recovery of a utility's investment. They must also eliminate, or at least greatly reduce, the issue of rate-case lag, especially when a utility engages in a sizable capital expenditure program.

Consistent with these views, S&P recently explained how recovery mechanisms, like PGE's PCAM, can play a key role in providing a regulated utility with timely recovery of prudent expenditures, thereby helping to mitigate the negative effects from regulatory lag:

> …there are ratemaking alternatives that can eliminate, or at least greatly reduce, the issue of rate-case lag, especially when a utility engages in an onerous construction program. Instead of significantly

> large rate base increases or lengthy rate moderation or phase-in plans, separate tariff provisions that allow for timely rate recognition during construction, without requiring a utility to file a formal rate case application, can gradually ease higher costs into rates, limiting the accumulation of financing costs. … the greater the percentage of a utility's rates that it recovers through fixed charges rather than volume-based charges, the greater the support for credit quality.[7]

Moody's agrees on the importance of regulation – and recovery of prudent expenditures – in the determining of credit ratings:

> For a regulated utility, the predictability and supportiveness of the regulatory framework in which it operates is a key credit consideration and the one that differentiates the industry from most other corporate sectors. The most direct and obvious way that regulation affects utility credit quality is through the establishment of prices or rates for the electricity, gas and related services provided (revenue requirements) and by determining a return on a utility's investment, or shareholder return. … However, in addition to rate setting, there are numerous other less visible or more subtle ways that regulatory decisions can affect a utility's business position. These can include the regulators' ability to pre-approve recovery of investments for new generation, transmission or distribution; to allow the inclusion of generation asset purchases in utility rate bases; to oversee and ultimately approve utility mergers and acquisitions; to approve fuel and purchased power recovery; and to institute or increase ring-fencing provisions. …
>
> The ability to recover prudently incurred costs in a timely manner is perhaps the single most important credit consideration for regulated utilities as the lack of timely recovery of such costs has caused financial stress for utilities on several occasions. For example, in four of the six major investor-owned utility bankruptcies in the United States over the last 50 years, regulatory disputes culminated in insufficient or delayed rate relief for the recovery of costs and/or capital investment in utility plant.[8]

---

[7] S&P Research: "Recovery Mechanisms Help Smooth Electric Utility Cash Flow and Support Ratings," March 9, 2009.

[8] Moody's Research: "Rating Methodology: Regulated Electric and Gas Utilities," August 2009.

V. Assessment of PGE's Credit Ratings

Q. What credit ratings does PGE currently hold?

A. On January 29, 2010, S&P downgraded PGE's corporate credit rating to 'BBB' and assigned a Stable Outlook. Moody's has maintained an equivalent 'Baa2' issuer rating on PGE, assigning a Positive Outlook on that rating on November 21, 2008.

In downgrading PGE's rating, S&P highlighted the recessionary economic environment in Oregon, and noted "a weak power cost mechanism and chronic under-earning of authorized returns," a situation that is problematic for a utility that relies "on power purchases for a significant portion of load [with] vulnerability to hydro variability, which necessitates careful management of power requirements."[9] In view of the difficulties that 'BBB'-rated companies faced during the recent financial crisis, I believe it is even more important for the Commission to modify PGE's PCAM to provide for timely recovery of actual fuel and purchased power costs on a timely basis. My recommendation to both the Company and its regulators is to target a return to the 'BBB+' rating level, with a longer term goal of achieving an 'A' category rating, which should alleviate both access and cost pressures related to ongoing financing needs. A key component of the agencies' analysis of the decision in this case will be the manner in which the Commission sets the framework for PGE's PCAM going forward.

---

[9] S&P Research: "Portland General Electric Co. Corporate Credit Rating Lowered to 'BBB' on Weak Economy; Outlook Revised to Stable," January 29, 2010.

VI. Operation of PGE's PCAM Should be Fairly Balanced

Q. You mentioned that you had experience with PCAMs during the time that you served as chairman of the Michigan PSC. Can you explain how you viewed that PCAMs should operate during that time?

A. Yes. I served as chairman of a commission that utilized a form of PCAM – and, I am glad to be able to say that while after-the-fact disallowances of fuel and power supply costs were rare, they did serve to motivate appropriate behavior on the part of utility managers.

Since the goal of the mechanism in Michigan was to only reimburse utilities for their prudent expenditures, utilities communicated with commission staff to ensure they were proceeding down the proper path. There was no need for forecasted levels to be locked into base rates as the sole means of cost recovery, because under the Michigan PCAM the companies knew they had an obligation to carry out their fuel procurement and purchased power activities prudently – and when they didn't, they knew they would be subject to a financial disallowance.

Based upon my time on the Michigan PSC, I view a key tenet of good regulation to be that a utility's prudent expenses made in order to provide an appropriate level of customer service and reliability are entitled to be fully and fairly recovered on a timely basis – and customers should not be required to pay an amount greater than those expenses. Price variations related to fuel and purchased power, as well as amounts utilized by the utility, can vary greatly from year-to-year. Notwithstanding the Annual Update Tariff that the Commission utilizes for PGE, it is very difficult to accurately forecast variations in hydro and wind based power supply based upon "normal" climatic factors. In the absence of a PCAM structured as I suggest, at any particular moment in time, based upon then-existing circumstances, rates might be set too low to allow the utility to recover all of its prudent expenditures or, alternatively, rates might be too high to accurately pass through costs to customers. The best way to avoid such a result is through use of a PCAM that affirmatively seeks to tie timely expense recovery to the actual costs prudently expended. I do not believe that PGE's current PCAM can achieve that aim.

Q. What problems do you see with PGE's current PCAM?

A. Before discussing the problems I see, I would be remiss if I did not note the positive nature of the step the OPUC took in 2007 to reinstate a PCAM for PGE. That action placed the OPUC among the large majority of state utility commissions that utilize some form of PCAM, and was very important for a utility that is facing substantial capital needs over the next several years.[10] Nonetheless, based upon my past regulatory and credit rating experience, I see problems with the framework that the Commission structured at that time. I firmly believe that the goal of a PCAM should be the timely recovery of all prudent costs expended by a utility for fuel and power supply in furtherance of providing reliable service to its customers. I do not believe that PGE's PCAM meets that standard.

Q. Why is that?

A. My difficulties with PGE's current PCAM fall into two areas, both of which cut against the goal of achieving utility recovery of actual prudent costs on a timely basis, while only charging customers for actual prudent costs:

[10] For a discussion of PGE's significant capital investment needs within the current challenging economic climate in Oregon, *See* the Company's Integrated Resource Plan Executive Summary.

1. the earnings test that the Commission has imposed; and
2. the asymmetric earnings deadband.

Q. Please explain the problem with the earnings test.

A. I view the earnings test, as structured, as an imperfect attempt to compel appropriate utility behavior, at the expense of sacrificing the goal of recovery of actual prudent costs with customers paying no more, no less. Such a framework ignores the greatest hammer that a utility regulator holds – the authority to review the prudency of a company's resource procurement activities with the ability to disallow imprudent expenditures. While that regulatory exercise may not pinpoint precisely actual costs going into rates, from my experience, it comes pretty close.

The same cannot be said for a PCAM mechanism where PGE could be underearning its authorized return on equity ("ROE") by 100 basis points, and not be reimbursed for actual prudent fuel expenses, notwithstanding the fact that the Company does not receive any return or benefit for the funds it lays out or the risk it is undertaking. The same situation holds on the customer side: PGE could be overearning by 100 basis points, which positive result might partially be driven by lower fuel costs, and the customer would still be paying more than the actual prudent fuel costs of the Company.[11] Even the one state in which I have worked that maintains an earnings test for PCAM recovery, Indiana, limits full recovery of fuel and purchased energy costs only *if* the regulated utility is earning above its net operating income authorized in the most recent rate case, and even then *only if* the

[11] Interestingly, under Senate Bill 408's income tax reconciliation, the imprecision embodied within each of those unbalanced scenarios was multiplied further by the Oregon Legislature – a fact acknowledged by this Commission in Order No. 07-015.

"overearnings" are greater than any "underearnings" the utility has incurred over the longer of the past five years or since the last rate case order.

Q. How do you view the asymmetric deadbands?

A. I believe the asymmetric deadbands exacerbate the problem. I have difficulty understanding why PGE, or any regulated utility, should absorb some portion of power costs, prudently incurred for the purpose of providing reliable customer service, and upon which the Company receives no return, just reimbursement. To make matters worse, that deadband is then skewed against the interest of the Company and its investors. For example, PGE estimates that its actual fuel and purchased power costs exceeded recovery by $22 million in 2009, but because that amount was within the asymmetric deadband, no additional recovery under the PCAM occurs.

Not surprisingly, the financial community has expressed concerns over this arrangement. In a report published on December 16, 2009, Bank of America Merrill Lynch stated:

> Unfortunately, [the PCAM] has a wide deadband ($45 million in 2009 or $0.43 per share) in which [PGE] absorbs 100% of the costs/benefits. Moreover, the deadband is weighted more heavily toward [PGE] absorbing more costs than retaining benefits. Due to the company's lack of control over hydro production and wind production, [PGE] has historically had meaningful earnings swings due to the PCAM.

That said, Bank of America Merrill Lynch is hopeful, concluding that while the:

> regulatory environment in Oregon historically has been challenging for utilities, which is understandable given the previous parent company [Enron,] …recent developments in Oregon regulation have been constructive. …We would be much more constructive if the Commission fixed the PCAM.[12]

[12] Bank of America Merrill Lynch Research: "Portland General Electric Company: Going Sideways – Initiate with Underperform," December 16, 2009.

In December 2009, Wells Fargo Securities voiced similar concerns about PGE's PCAM. While downgrading its expectations for the Company's future financial performance, it did note that they "would view any improvement to the PCAM deadbands … and/or SB 408 positively."[13]

Q. Do the views of the financial community surprise you?

A. No. The inconsistencies within PGE's PCAM are of substantial concern to investors, since the Company can do little to avoid either negative or positive impacts. I strongly recommend modifying the PCAM so that it is fair to the Company, its investors, and its customers: aligning actual prudent costs with what customers have to pay.

Q. The PCAM also includes a 90-10 sharing mechanism once the deadband is passed, either up or down. Does that aspect trouble you as well?

A. I am not sure the Company would agree with me, but while I would not add that sharing aspect if I were regulating PGE, I can understand why this Commission might. While the Michigan PSC did not inject such 90-10 sharing into the fuel recovery equation, some states have added that policy in as an added motivation toward proper utility attention to detail -- so I can accept that it might serve a regulatory purpose and the OPUC might choose to use it.

Q. Do you believe that, if the OPUC were to modify PGE's PCAM to reduce the deadbands and eliminate the ROE asymmetry, such change should be reflected in a authorized ROE?

[13] Wells Fargo Securities Research: "Regulated Electric Utilities – Downgrading POR," December 14, 2009.

A. No. I do not believe that providing actual prudent cost recovery on a timely basis represents a reduction in risk that should be reflected in a lower authorized ROE. As I allude to above, consideration of fuel costs in a manner that lowers uncertainty and risk represents the mainstream position on this issue across the United States. Thus, the financial community takes the presence of an effective PCAM as virtually a given when comparing utilities across jurisdictions for possible investment. Investors rely on the presence of such adjustment mechanisms to protect themselves from the variability of fuel and purchased power costs that are substantially outside the control of the affected utility, but which can have a substantial impact on the financial profile of that utility, even when prudently managed. Of course, fuel and power procurement is just one of a multitude of risks that a regulated electric utilities' faces in its day-to-day operations. Thus, even with these mechanisms mitigating a portion of the risk and uncertainty related to regulated utility's operations (and I note PCAMs relate to activities upon which most utilities do not receive a return), investors will still consider the business risks that remain and compare them to utilities in other jurisdictions. Those utilities ordinarily operate under recovery mechanisms more closely aligned with the modified PCAM I have proposed for PGE. I have long argued that regulatory lag is not a burden that regulated utilities should inherently be forced to bear.

Q. Do the rating agencies concur with your opinion?

A. I believe they do. S&P stated in November 2002 its opinion concerning the importance of electric utilities having the opportunity to recover fuel and purchased power expenses:

> When assessing the importance of productive regulation to the credit strength of an electric utility, something to consider is the means by which the utility can expect to recover variable expenses, particularly fuel and purchased-power expenses, which have highly erratic unit costs. Recent, and in some cases, extreme volatility in the U.S. wholesale electricity markets, as well as in the natural gas markets, underscores this importance. It is no coincidence that utilities with stronger fuel and power cost recovery mechanisms typically enjoy loftier credit ratings.

S&P went on to comment upon the negative aspects of the absence of a PCAM:

> In jurisdictions where [PCAMs] have been prohibited, electric utilities have always been subject to the uncertainties surrounding the recovery of incurred fuel and purchased-power expenses. With few exceptions, companies operating exclusively in these jurisdictions have always had ratings below the industry average.[14]

Q. Do the other rating agencies share S&P's positive views with regard PCAMs?

A. Yes they do. Moody's has commented upon the importance of PCAMs in mitigating operating risk:

> Cost Recovery Provisions: States have various policies with respect to fuel and wholesale power cost recovery, and the recent volatility in commodity prices have made these provisions important elements of a utility's cost management capability. Such provisions make it possible for utilities to quickly adjust rates in the event of an unexpected hike in fuel costs. Although the number of states permitting such recovery has declined, particularly in those that have transitioned to a competitive market, they remain critical risk mitigants to those utilities still operating in regulated environments.[15]

Fitch has discussed the credit implications of the presence of PCAMs:

> Fitch factors risks related to commodity price volatility into stress cases related to each company's individual circumstances and asset portfolios.... Potential risks for regulated distribution and integrated utilities: ... Utilities with frozen tariffs or those without the means to recover their higher fuel expense are most at risk.[16]

---

[14] S&P Research: "Constructive Regulation For U.S. Utilities Is More Important Than Ever," November 14, 2002.
[15] Moody's Global Credit Research: "Rating Methodology: Global Regulated Electric Utilities," March 2005.
[16] Fitch Special Report: "Electric Fuels Outlook: The Fuels Dilemma," November 11, 2004.

In February 2006, Fitch added these thoughts in a report discussing credit implications of commodity cost recovery:

> A utility's ability to weather a period of high and rising commodity costs is influenced by many related factors, including the state's market structure, rules regarding power procurement and the utility's obligation to serve customers' energy needs, the utility's resource mix relative to its load requirement, access to adequate liquidity and the state's regulatory/political environment. Within this context, **effective and timely commodity cost-adjustment mechanisms provide utilities with greater assurance of ultimate recovery in a rising energy price environment.** [Emphasis supplied.][17]

Then in June 2006, Fitch re-emphasized the impact that timely recovery of fuel and purchased energy expenses has on electric utility credit ratings:

> Volatile and higher energy and fuel commodity prices represent a challenge to electric utilities.... Given [the current] environment, Fitch believes timely recovery of fuel costs is essential to an electric utility's creditworthiness and that its response to high and volatile cost pressures will be a key determinant to a utility's credit quality and rating in 2006 and beyond.[18]

Q. With the U.S. utility sector experiencing significant volatility in fuel and purchased power costs during the past few years, what are the implications for PGE if the Commission were to leave the PCAM as is?

A. The past decade is replete with examples of regulators attempting to artificially hold the line on seemingly prudently incurred fuel and purchased power cost recovery solely because those costs were growing at a rapid rate. Such flawed decision-making can have very dire consequences for both utilities and their customers, as we have seen in California, Nevada, Arizona, Illinois, and now potentially in Florida. Properly structured PCAMs, with appropriate monitoring and decision-making tied

[17] Fitch Special Report: "U.S. Electric Utilities: Credit Implications of Commodity Cost Recovery," February 13, 2006.
[18] Fitch Special Report: "Cost Recovery and Public Power: Who Is at Risk?," June 1, 2006.

to prudence, are the best means to avoid negative financial consequences for regulated utilities.

Uncertainty with regard to fuel cost volatility is the very reason that a majority of states utilize a properly structured PCAM in the first place – so that a utility can carry out its responsibilities to provide reliable service to customers at the best cost available under then-existing circumstances, without having to be concerned that its prudent expenditures in this regard might be found to be unrecoverable at a later time. Because regulated utilities in most cases do not earn any profit or return on their fuel and purchased power expenditures, barring unusual behavior on the part of the utility, such expenses are presumed to be prudent, and rating agencies and investors expect that utilities will recover them without undue delay.

VII. Conclusion

Q. Do you have concluding thoughts?

A. Yes. The concept of utility regulation is to provide a surrogate for the competitive market that is not present when a company possesses monopoly or near-monopoly status with regard to an essential good, such as utility service. PCAMs attempt to align the costs that a utility expends for fuel and purchased power with its recovery of those costs on a timely basis. Such costs 1) can vary widely from year-to-year; 2) are substantially outside the control of the utility; and 3) represent a considerable financial outlay by a utility, with no ability to receive a return on those expended funds. By being able to recover prudently incurred costs expeditiously, a utility lowers the risk of its operations and achieves consistency with the level of risk faced by a wide majority of other utilities within the United States, all of which are chasing the same investor funds. It is wholly consistent with rational utility economics for customers to pay the actual costs of fuel and purchased power that are procured for customers' benefit, whether those costs are in an escalating mode or actually going down.

Finally, my advice to utility companies, investors and regulators alike is that nothing should be taken for granted in the current investing environment. Investors have choices, and a decision to take funds elsewhere leads to a higher cost of capital for Oregon's regulated utilities including PGE. I believe both the Company and the Commission should each undertake actions over which they have control so as to create an environment which will encourage the ratings agencies to improve their view of PGE so that the Company's ratings can return to the 'BBB+' level after conclusion of this rate case. A constructive Commission decision that provides a well-conceived modification to PGE's existing PCAM, so as to redirect the mechanism to provide full recovery of all prudent fuel and power supply costs on a timely basis, would represent an important step toward PGE stabilizing its financial standing vis-à-vis the capital markets.

Q. Does this conclude your testimony?

A. Yes it does.

List of Exhibits

PGE Exhibit	**Description**
1301	Educational and Professional Background

STEVEN M. FETTER

1489 W. Warm Springs Rd. -- Ste. 110
Henderson, NV 89014
732-693-2349
RegUnF@gmail.com
www.RegUnF.com

Education University of Michigan Law School, J.D. 1979
Bar Memberships: U.S. Supreme Court, New York, Michigan
University of Michigan, A.B. (Communications) 1974

April 2002 – Present
President – REGULATION UnFETTERED – Henderson, NV

Founder of advisory firm providing regulatory, legislative, financial, legal and strategic planning advisory services for the energy, water and telecommunications sectors, including public utility commissions and consumer advocates; federal and state testimony; credit rating advisory services; negotiation, arbitration and mediation services; skills training in ethics, negotiation, and management efficiency.

- Service on Boards of Directors of: CH Energy Group (Lead Independent Director; Chairman, Governance and Nominating Committee; Member, Audit; Previous Chairman, Audit Committee and Compensation Committee), National Regulatory Research Institute, Keystone Energy Board, and Regulatory Information Technology Consortium; Member, Wall Street Utility Group; Participant, Keystone Center Dialogues on RTOs and on Financial Trading and Energy Markets.

October 1993 – April 2002
Group Head and Managing Director; Senior Director -- Global Power Group, Fitch IBCA Duff & Phelps -- New York/Chicago

Manager of 18-employee ($15 million revenue) group responsible for credit research and rating of fixed income securities of U.S. and foreign electric and natural gas companies and project finance; Member, Fitch Utility Securitization Team.

- Led an effort to restructure the global power group that in three years time resulted in 75% new personnel and over 100% increase in revenues, transforming a group operating at a substantial deficit into a team-oriented profit center through a combination of revenue growth and expense reduction.

- Achieved national recognition as a speaker and commentator evaluating the effects of regulatory developments on the financial condition of the utility sector and individual companies; Cited by Institutional Investor (9/97) as one of top utility analysts at rating agencies; Frequently quoted in national newspapers and trade publications including The New York Times, The Wall Street Journal, International Herald Tribune, Los Angeles Times, Atlanta Journal-Constitution, Forbes and Energy Daily; Featured speaker at conferences sponsored by Edison Electric Institute, Nuclear Energy Institute, American Gas Assn., Natural Gas Supply Assn., National Assn. of Regulatory Utility Commissioners (NARUC), Canadian Electricity Assn.; Frequent invitations to testify before U.S. Senate (on C-Span) and House of Representatives, and state legislatures and utility commissions.

- Participant, Keystone Center Dialogue on Regional Transmission Organizations; Member, International Advisory Council, Eisenhower Fellowships; Author, "A Rating Agency's Perspective on Regulatory Reform," book chapter published by Public Utilities Reports, Summer 1995; Advisory Committee, Public Utilities Fortnightly.

March 1994 – April 2002
Consultant -- NYNEX -- New York, Ameritech -- Chicago, Weatherwise USA -- Pittsburgh

Provided testimony before the Federal Communications Commission and state public utility commissions; Formulated and taught specialized ethics and negotiation skills training program for employees in positions of a sensitive nature due to responsibilities involving interface with government officials, marketing, sales or purchasing; Developed amendments to NYNEX Code of Business Conduct.

October 1987 - October 1993
Chairman; Commissioner -- Michigan Public Service Commission -- Lansing

Administrator of $15-million agency responsible for regulating Michigan's public utilities, telecommunications services, and intrastate trucking, and establishing an effective state energy policy; Appointed by Democratic Governor James Blanchard; Promoted to Chairman by Republican Governor John Engler (1991) and reappointed (1993).

- Initiated case-handling guideline that eliminated agency backlog for first time in 23 years while reorganizing to downsize agency from 240 employees to 205 and eliminate top tier of management; MPSC received national recognition for fashioning incentive plans in all regulated industries based on performance, service quality, and infrastructure improvement.

- Closely involved in formulation and passage of regulatory reform law (Michigan Telecommunications Act of 1991) that has served as a model for other states; Rejuvenated dormant twelve-year effort and successfully lobbied the Michigan

Legislature to exempt the Commission from the Open Meetings Act, a controversial step that shifted power from the career staff to the three commissioners.

- Elected Chairman of the Board of the National Regulatory Research Institute (at Ohio State University); Adjunct Professor of Legislation, American University's Washington College of Law and Thomas M. Cooley Law School; Member of NARUC Executive, Gas, and International Relations Committees, Steering Committee of U.S. Environmental Protection Agency/State of Michigan Relative Risk Analysis Project, and Federal Energy Regulatory Commission Task Force on Natural Gas Deliverability; Eisenhower Exchange Fellow to Japan and NARUC Fellow to the Kennedy School of Government; Ethics Lecturer for NARUC.

August 1985 - October 1987
Acting Associate Deputy Under Secretary of Labor; Executive Assistant to the Deputy Under Secretary -- U.S. Department of Labor -- Washington DC

Member of three-person management team directing the activities of 60-employee agency responsible for promoting use of labor-management cooperation programs. Supervised a legal team in a study of the effects of U.S. labor laws on labor-management cooperation that has received national recognition and been frequently cited in law reviews (U.S. Labor Law and the Future of Labor-Management Cooperation, w/S. Schlossberg, 1986).

January 1983 - August 1985
Senate Majority General Counsel; Chief Republican Counsel -- Michigan Senate -- Lansing

Legal Advisor to the Majority Republican Caucus and Secretary of the Senate; Created and directed 7-employee Office of Majority General Counsel; Counsel, Senate Rules and Ethics Committees; Appointed to the Michigan Criminal Justice Commission, Ann Arbor Human Rights Commission and Washtenaw County Consumer Mediation Committee.

March 1982 - January 1983
Assistant Legal Counsel -- Michigan Governor William Milliken -- Lansing

Legal and Labor Advisor (member of collective bargaining team); Director, Extradition and Clemency; Appointed to Michigan Supreme Court Sentencing Guidelines Committee, Prison Overcrowding Project, Coordination of Law Enforcement Services Task Force.

October 1979 - March 1982
Appellate Litigation Attorney -- National Labor Relations Board -- Washington DC

Other Significant Speeches and Publications

- Perspective: Don’t Fence Me Out (Public Utilities Fortnightly, October 2004)

- Climate Change and the Electric Power Sector: What Role for the Global Financial Community (during Fourth Session of UN Framework Convention on Climate Change Conference of Parties, Buenos Aires, Argentina, November 3, 1998)(unpublished)

- Regulation UnFettered: The Fray By the Bay, Revisited (<u>National Regulatory Research Institute Quarterly Bulletin</u>, December 1997)

- The Feds Can Lead…By Getting Out of the Way (<u>Public Utilities Fortnightly</u>, June 1, 1996)

- Ethical Considerations Within Utility Regulation, w/M. Cummins (<u>National Regulatory Research Institute Quarterly Bulletin</u>, December 1993)

- Legal Challenges to Employee Participation Programs (American Bar Association, Atlanta, Georgia, August 1991) (unpublished)

- Proprietary Information, Confidentiality, and Regulation's Continuing Information Needs: A State Commissioner's Perspective (Washington Legal Foundation, July 1990)

Table of Contents

I. Introduction and Summary

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

A. My name is Ham T. Nguyen. I am employed by PGE as a Senior Economist. I am responsible for developing PGE's end-use customer energy forecast. My qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. My testimony presents and explains the methodology and processes underlying PGE's 2011 test-year forecast of 19,243 million kilowatt-hours (kWh), on a cycle-month (billing) basis, delivered to end-use customers, including deliveries to customers who opted out of PGE cost of service rates for direct access under Schedules 483 and 489.

Q. What is your forecast?

A. I project that deliveries to all end-use customers will be 19,243 million kWh for test-year 2011, essentially flat from the 2009 weather-adjusted actual deliveries of 19,230 million kWh. This 2011 total kWh delivery takes into account the effect on demand of anticipated higher electricity prices in 2011 (compared to 2009 base period prices), savings from "incremental" energy efficiency (EE) programs (funded through *Schedule 109 Incremental Energy Efficiency Funding* per SB 838), and impacts of Advanced Meter Infrastructure (AMI) programs.

There are four forecasts for the test year. They are B (base), P (price-effect), E (post price effect and "incremental" EE programs) and M (post price effect, EE programs and AMI programs) forecasts. The B forecast considers the effect of economic activities on electricity delivery, all else equal. The P forecast incorporates the impact of higher electricity prices on delivery. The E forecast specifically accounts for the savings from incremental EE programs. The M forecast factors the benefits from full AMI implementation in 2011. PGE Exhibits 1401, 1402, 1403 and 1404 show four detailed kWh delivery forecasts.

Table 1 below summarizes the kWh delivery forecast in annual percentage changes by end-use sector from 2008 through 2011. The net saving of the AMI programs, due for completion by the end of 2010, however, is small, worth about 8.2 million kWh (roughly 1 MWa) in 2011. Forecast M thus consists of mostly savings from SB 838 programs.

Table 1
Percent Change in kWh Delivery from Preceding Year: 2008-2011

Sector	2008[1]	2009[1]	2010 (B)[2]	2010 (M)[3]	2011 (B)[2]	2011 (M)[3]
Residential	1.0%	1.1%	(1.2%)	(1.4%)	0.9%	(0.6%)
Commercial	(0.1%)	(1.3%)	(0.3%)	(0.8%)	1.5%	0.4%
Industrial	2.1%	(10.2%)	3.4%	3.2%	1.7%	1.0%
Miscellaneous	0.6%	(0.6%)	4.0%	4.0%	1.3%	1.3%
Total Retail	0.8%	(2.4%)	0.2%	(0.1%)	1.3%	0.2%

[1] Weather-adjusted actual
[2] SDEC09B Base
[3] SDEC09M, Post price, EE & AMI

Q. Why do you adjust your 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, implementing housekeeping measures and, over time, making changes to the capital stock such as appliances and equipment that would reduce energy consumption.

Q. How do you specifically account for the impact of a price change in the test-year forecast?

A. We calculate the implied demand elasticity of the price model by varying price levels, e.g., by 10%. Demand elasticity is the ratio of the percent change in demand, kWh delivery in this case, to the percent change in "real" price. For the test-year forecast, we first calculated the kWh demand change based on an assumed price change and the estimated price elasticity, and then adjusted the base forecast by the demand change estimate. This is the same procedure used in previous rate cases.

Q. What price change assumptions did you make to calculate the price effect on demand?

A. We assumed no price change in 2010. In 2011, we assumed prices for residential customers and non-residential customers to be 12% above October 2009 levels in "nominal" terms and 10.6% in "real" terms. October 2009 is the last historical data point.

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

A. We used elasticity estimates of -0.08 for residential demand and -0.03 for nonresidential demand. They were derived from the "price" model that was re-estimated in September 2009 and remain essentially unchanged from previous estimates. A price elasticity of -0.08 means that if electricity prices rose an average of 10%, kWh demand would decline by 0.8%, all else equal. As we pointed out in UE 180 and UE 197, these elasticity estimates have remained stable since 2002. Using these estimates of elasticity and the assumed price increases, the price-effect (P) forecast is about 98.5 million kWh or 0.5% lower than the base (B) forecast for 2011.

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.

The assumed EE program levels incorporate new funding for EE programs beyond prior levels, starting in November 2009. The Energy Trust of Oregon (ETO) developed the estimates of these “incremental savings” for PGE based on measures achievable at a levelized cost of up to 6.5 cents per kWh. We assumed these EE savings to have an effect beginning in November 2009 and ramping up gradually through 2011.

Q. How significant is the impact of these incremental energy efficiency programs savings on PGE’s delivery forecast?

A. We estimate a total of 174.1 million kWh or 0.9% savings from these programs in the 2011 test year. PGE Exhibit 1405 shows the savings from the incremental energy efficiency programs that are included in PGE’s delivery forecast. The savings were estimated by the Energy Trust of Oregon (ETO).

Q. Did you include any benefits associated with the Advanced Metering Infrastructure (AMI) program in the forecast?

A. Yes. We included estimates of two AMI-related benefits: “Remote Disconnect” (RD) and “Lost Revenue Protection” (LRP) in the delivery forecast. RD speeds up the disconnect process in the residential sector, thus reducing power deliveries that are likely to be written off by PGE. AMI enhances the identification of unaccounted-for energy occurring primarily as energy theft, raising the kWh billed to both residential and commercial customers. We estimate RD to decrease energy delivery by 20.4 million kWh to residential customers and LRP to increase energy delivery by 12.3 million kWh to both residential and commercial customers.

Q. How does the 2011 delivery forecast compare to recent history?

A. The delivery forecast of 19,243 million kWh to end-use customers for test-year 2011 is 0.2% higher than the 2010 average-weather delivery forecast of 19,212 million kWh. The end-use customer forecast for 2011 is 0.1% above the 2009 weather-adjusted delivery of 19,230 million kWh and 4.8% below the average-weather delivery of 20,214 million kWh we settled in UE 197 for test-year 2009. The delivery forecast for 2011 is also 2.4% below the 2008 weather-adjusted delivery of 19,709 million kWh that occurred as the "Great Recession" of 2008/2009 unfolded. The recession, one of the worst since the Great Depression, has had a great impact on the economy and, in the case of Oregon, an outsized impact on resource-based industries, such as metals and paper products, which are large energy users. PGE delivery of energy to end-use customers on a weather-adjusted basis fell 2.4% in 2009, a sharp decline, only exceeded by the 3.4% drop in 1982 and the 3.6% drop in 2001. The drop in 2009 energy delivery resulted from double-digit declines in deliveries to the lumber, metals, and paper industries. The drop was most severe for the paper industries, which took 30% less energy in 2009 than in 2008. Higher delivery of energy to residential customers essentially offset lower delivery to commercial customers in 2009.

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. However, we re-estimated the model using the most current data, an extended historical period through October 2009. Re-estimation 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. We retained the structure (specification) but re-estimated the base model to include new information, examining the results for any changes in the coefficients and, if necessary, re-specifying the relevant equations. Finally, we used the most recently available forecasts of the drivers or independent variables to develop our load forecast.

Q. Are these models new or different from previous PGE load models?

A. Except for the re-estimation of the coefficients, performed to capture any behavioral or structural changes over time, the forecast model specification remains the same as that used in previous filings with the Commission. I described in detail the theory and specification of our model, as well as our forecast processes, in my previous testimonies on PGE's load forecast. These were submitted in various regulatory proceedings, most recently in UE 197 (PGE Exhibit 1100) and in UE 180 (PGE Exhibit 1200).

Q. Why do you need to re-estimate the model?

A. To capture evolving changes in customer behavior or mode of operation as early as possible, PGE re-estimates the load model to reflect the most current customer-to-energy relationships. These relationships could change significantly in the events of a war, natural disaster, severe economic downturn or sharp price hikes. If we do not re-estimate our models to reflect such changes, the models, in all likelihood, would produce inaccurate forecasts. Timely re-estimation is crucial as we pass through one of the most severe economic downturns since the Great Depression.

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 Department of Administrative Services, Office of Economic Analysis (OEA) provides the Oregon economic forecast (Oregon Economic and Revenue Forecast) and the Oregon Employment Department provides the state unemployment forecast. The California Employment Development Department (EDD) provides the forecast of the California economy. The Global Insight forecast and the California EDD forecast were obtained in November 2009 and the OEA forecast in December 2009. In addition, customers who are large energy users provide us with specific operation information, direct inputs and, if available, forecast of energy use. We used these same sources of information to develop our forecasts of kWh delivery in our previous filings with the Commission.

Q. Did you make any changes to the model?

A. No. Except for the re-estimation, we made no changes to the structure of the model.

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

A. The accuracy of a forecast depends not only on the performance of the model specification but also on the performance of the independent variables driving the forecast. In our model, the independent variables include temperature and other weather variables that affect energy use. Since UE 180, we have been using 15-year moving averages to represent forward-looking weather conditions.

Q. How current are the data you use to estimate the model?

A. We use the most recent historical kWh deliveries and economic data to estimate the model and develop the forecast. For the development of the model in this proceeding, we used data from 1985 through October 2009 for the residential equations and data from 1990 through October 2009 for the nonresidential equations. A limitation of the NAICS- (North America Industry Classification System) based Oregon employment data dictated the latter choice; this data was not available prior to 1990.

Q. What end-use sectors do you forecast in the model?

A. We forecast demand (kWh delivery) by residential, commercial, manufacturing (industrial) customers and energy served under miscellaneous rate schedules. Residential customers are mostly households, but also include dwellings that PGE has connected for electrical service that are not yet occupied. Commercial customers typically are businesses providing services, such as retail and wholesale establishments, schools, hospitals, government and financial institutions. Manufacturing customers include producers of paper, lumber, steel, machinery, micro-processors, computers, truck and aircraft parts, and shipyards, among others, that serve national and global markets.

In our model, we group commercial and manufacturing customers according to the NAICS definition of business segments. We develop the kWh projections for the three end-use sectors separately and then sum them together with the forecast of existing miscellaneous schedules (streetlight, irrigation, etc.) to obtain total end-use energy.

Finally, we allocate these NAICS-segment delivery forecasts into voltage-level (rate schedule) kWh deliveries using their respective preceding-year ratios. We described in detail these sectors' model specifications and forecast processes in UE 197 and UE 180 testimonies.

Q. Do you make any changes or adjustments to the forecast?

A. We adjust the base (B) delivery forecast results to account for impacts on delivery from any electricity price changes, incremental EE programs and AMI projects.

Q. How do you forecast the ultimate loads delivered to the PGE distribution system?

A. This process involves three steps: 1) aggregate cycle-based sector kWh deliveries into various voltage service levels, 2) convert cycle-based deliveries to calendar-based deliveries and 3) add transmission and distribution losses to voltage-service level kWh deliveries to calculate system load in average MW and in MW demand (peak) at the bus bar.

Q. What is the voltage aggregation process?

A. Different customers require different voltage levels to run their appliances or equipment. Residential, most commercial, and some manufacturing customers require *secondary* voltage services (less than 11,000 volts). Most manufacturing and some commercial customers require *primary* voltage services (between 11,000 volts and 57,000 volts). Large manufacturing customers require services at “transmission” voltage (equal to or greater than 57,000 volts). We prorate projected kWh deliveries to commercial and manufacturing customers by the most recent service-level allocation factors at the NAICS level to obtain the forecast of kWh deliveries by voltage service levels.

Q. How do you calculate the ultimate load?

A. First we convert cycle-based energy deliveries to calendar-based deliveries using cycle-to-calendar ratios. We then add transmission and distribution (line) losses to the kWh deliveries at the meter to obtain the gross (or bus bar) average MW required to meet the end users' demand. For test year 2011, we apply line loss factors based on those used in UE 197 and adjusted for the AMI effect. We use monthly and annual voltage-level load factors to calculate the monthly MW and annual peak MW based on the projected average MW. PGE Exhibit 1411 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 your residential sector forecast?

A. We project 2010 deliveries of 7,683 million kWh using the base model (B) and a lower forecast of 7,667 million kWh to 718,072 residential customers after accounting for the effects of incremental energy efficiency programs (E). We assumed no price change in 2010 and no savings from AMI in 2010. For the test-year 2011, we forecast deliveries of 7,755 million kWh (B) and 7,624 million kWh (M), respectively, to 723,630 residential customers. The assumed price increase, the incremental energy efficiency programs and the AMI programs each and all combine to reduce deliveries in 2011. These delivery levels reflect a +0.9% (B) and -0.6% (M) change from 2010 to 2011, compared to an actual 1.1% growth in kWh delivery, adjusted for weather, in 2009. Both forecasts include outdoor area lighting energy.

The forecasts include projections of 6,252 new residential connects in 2010 and 7,478 in 2011. The 2011 levels are above the total new residential connects of 6,822 in 2008 and 3,813 in 2009, likely the trough of the current housing market cycle. We forecast 0.5% growth in the number of residential customers in 2010 and 0.8% in 2011, compared to a 0.5% increase in 2009. PGE Exhibit 1406 shows the forecast of building permits, new connects, and occupied accounts. PGE Exhibit 1407 displays the forecast of kWh use per occupied account and deliveries to residential customers in detail.

Q. What are the key results of your commercial sector forecast?

A. We project deliveries to NAICS-based commercial customers of 7,075 million kWh using the base (B) model and 7,041 million kWh after accounting for the effect of incremental energy efficiency programs for 2010 (E). We assumed no price change in 2010 and no savings from AMI in 2010. For test-year 2011, we forecast deliveries of 7,181 million kWh in the base (B) forecast and 7,069 million kWh in the adjusted (M) forecast. As with residential customers, we expect rising electricity prices to have an impact on kWh delivery to commercial customers, albeit to a lesser degree due to this sector's *inelastic* demand response (i.e., relatively small nonresidential price elasticity). On the other hand, the savings from incremental energy efficiency programs in the commercial sector are larger than those in the residential sector. The AMI programs are expected to raise, not to reduce, kWh delivery in the commercial sector due to the LRP benefit. We forecast energy delivery to this market segment - after accounting for price impacts, EE program savings and AMI benefits - to decrease 0.8% in 2010 as economic weakness persists while EE programs ramp up, but to increase 0.4% in 2011 as the economy strengthens sufficiently to offset the savings generated from incremental EE programs. Delivery to this market segment, adjusted for weather, declined 1.3% in 2009. PGE Exhibit 1408 contains the detailed forecast of deliveries to commercial consumers.

Q. What are the key results of your manufacturing sector forecast?

A. We project total deliveries to NAICS-based manufacturing (industrial) customers of 4,285 million kWh using the base model (B) and 4,278 million kWh accounting for price and energy efficiency savings (E) for 2010. For the test-year 2011, we forecast deliveries of 4,357 million kWh (B) and 4,320 million kWh accounting for price, energy efficiency and AMI savings (M). We expect only minimal response to electricity price changes due to the industrial sector's *inelastic* response and a slightly larger impact from incremental energy efficiency programs. We forecast delivery (M) to industrial customers to increase 3.2% in 2010 and 1.0% in 2011. We have included in the delivery forecast the expected completion and gradually increasing operation of two solar cell and panel manufacturers and expansion of one non-solar company that have constructed plants in the Portland metro area. Delivery to this market segment declined 10.2% in 2009. PGE Exhibit 1409 contains the detailed delivery forecast of the manufacturing sector.

PGE's manufacturing sector is concentrated in a few energy-intensive industries and large customers. In 2009, high tech industry accounted for over 42% of all industrial energy delivery, the paper industry at roughly 21% and metals at 11%. Among these, the top dozen customers alone accounted for almost 60% of delivery. As a result, when one or several of these large manufacturing customers decide to add capacity or to shut down operations in response to economic conditions, they have a significant impact on our energy delivery forecast.

IV. Direct Access Forecasts

Q. Did you make a separate forecast of delivery to Schedule 483/489 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 few customers who chose service under Schedule 483/489 (non-COS) by 2009 year-end. Schedule 483/489 is the only service under which customers may not receive COS pricing. We pro-rated COS and non-COS deliveries by applying the forecasted kWh shares of these customers to their respective service level or revenue class. PGE Exhibit 1412 shows a forecast of COS and NCOS (Schedule 483/489) deliveries for test-year 2011.

Q. Do you recommend a specific forecast or forecasts of test-year 2011 kWh delivery to end-use customers for ratemaking purposes?

A. Yes. I recommend the adoption of the M (post price, energy efficiency and AMI) forecast of 19,243 million kWh delivery to all customers and the forecast of 18,529 million kWh delivery to COS customers for test-year 2011.

V. Forecast Uncertainty

Q. How do you propose to address kWh delivery forecast uncertainty?

A. We can reduce uncertainty by using more 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 2011 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, the model. This would include additional actual load data, more current economic data and forecasts for the US and Oregon and large customers' usage forecasts and other components such as demand elasticity and price changes.

Q. Is there risk associated with this forecast?

A. Yes, somewhat. The kWh delivery forecast we submit in this filing is our "expected" or mid-point estimate. As such, it is a 50/50 "point" forecast, 50 percent chance that the actual outcome falls short or exceeds the forecast, typical for "baseline" projections. As with any estimate, actual conditions may differ from what we assumed or anticipated in the forecast, rendering a different outcome.

Q. What are the drivers of uncertainty in your forecast?

A. Our forecast depends on the stability of our model and the accuracy of input assumptions. Our model typically performs well over the *sample* period, the span over which we estimate the model, as it captures most, if not all, behaviors and relationships such as economic activities or customer response to price changes on energy use. We expect our model to perform equally well over the forecast period if these relationships remain unchanged or *stable*. If such relationships change in the test year period in response to significant events that were not anticipated or have never occurred over the historical period, our model will become outdated, or in statistical language *mis-specified*, leading to inaccurate forecasts.

The other areas of uncertainty, outside of weather variances, involve input assumptions such as the economy, electricity prices, key customers' operation decisions, new customers' entry or existing customers' exit and the absence of unforeseen natural disasters, wars or geopolitical turmoil. These variables' future outcomes could turn out differently than anticipated, resulting in a significant variance from the forecast.

Q. Are the input assumptions PGE uses to drive its forecast deterministic or subject to uncertainty?

A. All input assumptions are subject to uncertainty. PGE used as key drivers the November 2009 Global Insight and December 2009 Oregon OEA *baseline* economic forecasts that could change going forward as these organizations develop newer forecasts. These economic forecasts have their own issues of uncertainty. Global Insight at this point maintains a fairly symmetrical risk distribution, assigning 60% probability of occurrence to its November 2009 *baseline* U.S. economic forecast, 20% probability to its *Low Scenario* (False Dawn) and 20% probability to its *High Scenario* (V-Shaped Recovery). As economic realities unfold, Global Insight will likely adjust their baseline forecast as well as their uncertainty distribution as they have in the past. The Oregon OEA uses *stochastic* techniques to develop its uncertainty band. For 2011, OEA (December 2009) forecasts total Oregon employment to grow 2.2% from 2010 (1.3% from 2009) in its *baseline* case, bounded by 1.7% growth (0.2% decline from 2009) in the low case and 2.7% growth (2.9% from 2009) in the high case. Finally, PGE's key customers could operate differently than planned. They could shut down plants, curtail operations, or add new capacity that we did not anticipate or include in the forecast because of their own economic or unique circumstances. One of our large paper customers recently filed for bankruptcy protection, rendering its future operation uncertain at best. We specifically included in this forecast completion and operation of two large solar-panel manufacturers that located to Oregon in 2009 and other high-tech customers' expansions. If any of these assumptions fails to materialize, significant deviations from the test-year forecast would result. The risk here is skewed to the downside as we included known upside potential (expansion) in the forecast.

Q. Do changing economic conditions have an effect on your forecast?

A. Yes. The November 2009 Global Insight US forecast, in its baseline case, envisions the GDP to grow 2.2% in 2010 and 2.9% in 2011 and payroll employment to decline in 2010 before growing 1.7% in 2011. The OEA baseline forecast similarly anticipates Oregon payroll employment to decline through 2010 before growing 2.2% in 2011. Both forecasts were predicated on a number of assumptions including the effectiveness of on-going fiscal and monetary stimuli. In fact, Global Insight warned in its more recent (December 2009) US economic forecast that "the risk of a *Hard W*, i.e., a double-dip, recession is still uncomfortably high, a one in five chance." Such an outcome would clearly lead to a significantly lower 2011 test-year delivery than we currently forecast. This indeed happened in 2009 when the 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% in 2009 and OEA projected Oregon nonfarm payrolls to gain 0.3% in 2009. Oregon payrolls dropped 5.1% in 2009 and US GDP declined 2.4% in 2009. Actual energy delivery by PGE, adjusted for weather, was 4.8% below our test-year 2009 forecast that was based on the August 2008 Global Insight and September 2008 OEA economic forecasts.

Q. Is weather also an area of uncertainty?

A. Yes. In UE 180, PGE discussed extensively the uncertainty of the delivery forecast with regard to weather in terms of the *average* or the *mean* condition and the *variance* or *departure from the average* condition in the forecast year. The impact of this uncertainty, expressed as deviation from the mean, is significant because of the large impact of temperature on kWh usage. PGE estimates that one degree variation in temperature could affect (total retail) kWh usage by as much as 1.2% in peak months and as much as 0.7% on an annual basis.

Q. How much can the results vary for these areas of uncertainty?

A. If history is a guide, the effect can be substantial. For example, actual kWh deliveries deviated as much as 8.5% below the 2002 test-year forecast (UE 115) for a number of reasons that included the economic downturn, the aftermath of the West Coast energy crisis and the urgency it generated, the effect of the September 11 attack, and the weather.

Q. How did PGE's forecast of loads for the 2009 test year in UE 197 compare to the 2009 weather-adjusted actuals in light of the impact of the 2008/2009 Great Recession?

A. Actual deliveries fell as much as 4.8% below the 2009 test-year forecast (UE 197).

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. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
1401	(Non-Price) Delivery Forecast by market Segment and Service Level
1402	(Price Effect) Delivery Forecast by market Segment and Service Level
1403	(Post Price & EE) Delivery Forecast by Market Segment and Service Level
1404	(Post Price, EE & M) Delivery Forecast by Market Segment and Service Level
1405	Forecast of Incremental Energy Efficiency Program Savings
1406	Residential Building Permits, New Connects, Vacancy Rates and Occupied Accounts
1407	Forecast of Residential Use per Occupied Account and Ultimate Deliveries
1408	Commercial Deliveries Forecast by NAICS Cluster
1409	Industrial Deliveries Forecast by NAICS Cluster
1410	Forecast of Deliveries under Miscellaneous Secondary Rate Schedules
1411	Total Deliveries and Demand Forecast
1412	Forecast of Deliveries to Cost-of Service and Non-Cost-of-Service Customers

Delivery Forecast (Base) by Market Segment and Service Level

(At average weather)

Base (not adjusted) Forecast [1]

	(In million kWh)				% Change [2]		
	2008	2009[3]	2010	2011	2009	2010	2011
Schedule 7	7,684	7,772	7,683	7,755	1.1%	(1.2%)	0.9%
Residential Lighting	7	7	7	7	(0.4%)	2.0%	1.0%
Total Residential	7,691	7,779	7,690	7,763	1.1%	(1.2%)	0.9%
Commercial [4]	7,192	7,095	7,075	7,181	(1.3%)	(0.3%)	1.5%
Manufacturing [4]	4,613	4,144	4,285	4,357	(10.2%)	3.4%	1.7%
Miscellaneous Customers	213	212	220	223	(0.6%)	4.0%	1.3%
Secondary Voltage	7,546	7,337	7,312	7,444	(2.8%)	(0.3%)	1.8%
Total General Service	7,759	7,549	7,532	7,666	(2.7%)	(0.2%)	1.8%
Primary Voltage Service	2,811	2,882	3,111	3,097	2.5%	7.9%	(0.5%)
Transmission Voltage Service	1,447	1,019	937	997	(29.6%)	(8.1%)	6.5%
Total Retail [5]	19,709	19,230	19,270	19,524	(2.4%)	0.2%	1.3%

[1] SDEC09B
[2] calculated from un-rounded numbers
[3] includes actual weather-adjusted kWh through December 2009
[4] by NAICS grouping
[5] Total Retail equals Total Residential + Commercial + Manufacturing + Miscellaneous Customers or equals Total Residential + Total General Service + Primary Voltage Service + Transmission Service; total may not match due to rounding

Delivery Forecast (Price) by Market Segment and Service Level

(At average weather)

Net of Price Elasticity[1]

	(In million kWh)				% Change[2]		
	2008	2009[3]	2010	2011	2009	2010	2011
Schedule 7	7,684	7,772	7,683	7,687	1.1%	(1.2%)	0.1%
Residential Lighting	7	7	7	7	(0.4%)	2.0%	1.0%
Total Residential	7,691	7,779	7,690	7,694	1.1%	(1.2%)	0.1%
Commercial [4]	7,192	7,095	7,075	7,166	(1.3%)	(0.3%)	1.3%
Manufacturing [4]	4,613	4,144	4,285	4,342	(10.2%)	3.4%	1.3%
Miscellaneous Customers	213	212	220	223	(0.6%)	4.0%	1.3%
Secondary Voltage	7,546	7,337	7,312	7,418	(2.8%)	(0.3%)	1.4%
Total General Service	7,759	7,549	7,532	7,640	(2.7%)	(0.2%)	1.4%
Primary Voltage Service	2,811	2,882	3,111	3,093	2.5%	7.9%	(0.6%)
Transmission Voltage Service	1,447	1,019	937	997	(29.6%)	(8.1%)	6.5%
Total Retail [5]	19,709	19,230	19,270	19,425	(2.4%)	0.2%	0.8%

[1] SDEC09P
[2] calculated from un-rounded numbers
[3] includes actual weather-adjusted kWh through December 2009
[4] by NAICS grouping
[5] Total Retail equals Total Residential + Commercial + Manufacturing + Miscellaneous Customers or equals Total Residential + Total General Service + Primary Voltage Service + Transmission Service; total may not match due to rounding

Delivery Forecast (Price & Incremental EE) by Market Segment and Service Level

(At average weather)

Net of Price Elasticity and PGE Energy Efficiency[1]

	(In million kWh)				% Change[2]		
	2008	2009[3]	2010	2011	2009	2010	2011
Schedule 7	7,684	7,772	7,667	7,638	1.1%	(1.4%)	(0.4%)
Residential Lighting	7	7	7	7	(0.4%)	2.0%	1.0%
Total Residential	7,691	7,779	7,674	7,645	1.1%	(1.4%)	(0.4%)
Commercial [4]	7,192	7,095	7,041	7,064	(1.3%)	(0.8%)	0.3%
Manufacturing [4]	4,613	4,144	4,278	4,319	(10.2%)	3.2%	1.0%
Miscellaneous Customers	213	212	220	223	(0.6%)	4.0%	1.3%
Secondary Voltage	7,546	7,337	7,274	7,303	(2.8%)	(0.9%)	0.4%
Total General Service	7,759	7,549	7,494	7,526	(2.7%)	(0.7%)	0.4%
Primary Voltage Service	2,811	2,882	3,108	3,082	2.5%	7.8%	(0.8%)
Transmission Voltage Service	1,447	1,019	937	997	(29.6%)	(8.1%)	6.5%
Total Retail [5]	19,709	19,230	19,212	19,251	(2.4%)	(0.1%)	0.2%

[1] SDEC09E
[2] calculated from un-rounded numbers
[3] includes actual weather-adjusted kWh through December 2009
[4] by NAICS grouping
[5] Total Retail equals Total Residential + Commercial + Manufacturing + Miscellaneous Customers or equals Total Residential + Total General Service + Primary Voltage Service + Transmission Service; total may not match due to rounding

Delivery Forecast (Price & Incremental EE & AMI) by Market Segment and Service Level

(At average weather)

Net of Price Elasticity, PGE Energy Efficiency and AMI [1]

	(In million kWh)				% Change [2]		
	2008	2009[3]	2010	2011	2009	2010	2011
Schedule 7	7,684	7,772	7,667	7,624	1.1%	(1.4%)	(0.6%)
Residential Lighting	7	7	7	7	(0.4%)	2.0%	1.0%
Total Residential	7,691	7,779	7,674	7,631	1.1%	(1.4%)	(0.6%)
Commercial [4]	7,192	7,095	7,041	7,069	(1.3%)	(0.8%)	0.4%
Manufacturing [4]	4,613	4,144	4,278	4,320	(10.2%)	3.2%	1.0%
Miscellaneous Customers	213	212	220	223	(0.6%)	4.0%	1.3%
Secondary Voltage	7,546	7,337	7,274	7,309	(2.8%)	(0.9%)	0.5%
Total General Service	7,759	7,549	7,494	7,531	(2.7%)	(0.7%)	0.5%
Primary Voltage Service	2,811	2,882	3,108	3,083	2.5%	7.8%	(0.8%)
Transmission Voltage Service	1,447	1,019	937	997	(29.6%)	(8.1%)	6.5%
Total Retail [5]	19,709	19,230	19,212	19,243	(2.4%)	(0.1%)	0.2%

[1] SDEC09M

[2] calculated from un-rounded numbers

[3] includes actual weather-adjusted kWh through December 2009

[4] by NAICS grouping

[5] Total Retail equals Total Residential + Commercial + Manufacturing + Miscellaneous Customers or equals Total Residential + Total General Service + Primary Voltage Service + Transmission Service; total may not match due to rounding

Forecast of Incremental Energy Efficiency (EE) Savings

(In million kWh)

	2009[1]	2010	2011
Base (B) Forecast	19,230	19,270	19,524
Price (P) Forecast	19,230	19,270	19,425
Incremental EE Savings [2]	5.2	10.6	15.6
Schedule 109 Savings [3]	0.9	57.6	174.1
Post-EE Forecast (E) [4]	19,230	19,212	19,251

[1] kWh are actual adjusted for weather through December 2009; EE savings starting in November 2009

[2] Energy Trust of Oregon (ETO) year-end MWa estimates

[3] ETO estimates ramped in monthly; annual totals are cumulative over the period starting November 2009

[4] equals Price (P) Forecast minus Schedule 109 savings staring 2009

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

	2008	2009[1]	2010	2011[2]
Building Permits [3]				
Single-Family	7,865	5,935	13,788	17,922
Multiple-Family	4,338	1,873	5,322	6,016
New Connects				
Single-Family	3,077	1,845	3,184	3,668
Multiple-Family	3,617	1,874	2,828	3,570
Mobile Home	115	92	180	180
Other	13	2	60	60
Total Connects	6,822	3,813	6,252	7,478
Vacancy Rates (%)				
Single-Family	4.6%	4.6%	4.8%	4.9%
Multiple-Family	8.9%	9.4%	9.4%	9.4%
Mobile Home	9.1%	8.3%	9.5%	9.5%
Number of Occupied Accounts				
Single-Family Heat	104,171	104,188	103,849	103,907
Single-Family Non-Heat	323,206	324,695	325,425	327,425
Multiple-Family Heat	155,416	155,358	155,945	157,002
Multiple-Family Non-Heat	47,526	48,496	49,735	51,663
Mobile Home Heat	28,061	28,263	27,790	27,697
Mobile Home Non-Heat	3,531	3,563	3,498	3,484
Other	5,318	5,230	5,241	5,254
Total Occupied Accounts	667,226	669,794	671,483	676,432
Total Number of Accounts [4]	710,991	714,377	718,072	723,630

[1] includes actual through December 2009, except for building permits and connects which include actual through November 2009
[2] identical for both base, price-effect, EE and post AMI forecasts
[3] Oregon
[4] includes vacant accounts

Forecast of Residential Use per Occupied Account and Ultimate Deliveries

(At average weather)

	2008[1]	2009[2]	2010	2011
Use per Occupied Account (kWh)[3]				
Single-Family Heat	16,741	16,741	16,489	16,580
Single-Family Non-Heat	11,151	11,275	11,159	11,190
Multiple-Family Heat	9,480	9,551	9,442	9,478
Multiple-Family Non-Heat	6,561	6,759	6,663	6,692
Mobile Home Heat	16,124	16,115	15,764	15,849
Mobile Home Non-Heat	11,903	12,043	11,765	11,761
Other	10,664	10,932	10,624	10,472
Average Use per Occupied Account	11,517	11,604	11,441	11,465
Ultimate Deliveries (millions of kWh)[4]				
Single-Family Heat	1,744	1,744	1,712	1,723
Single-Family Non-Heat	3,604	3,661	3,632	3,664
Multiple-Family Heat	1,473	1,484	1,472	1,488
Multiple-Family Non-Heat	312	328	331	346
Mobile Home Heat	452	455	438	439
Mobile Home Non-Heat	42	43	41	41
Other	57	57	56	55
Schedule 7 Deliveries	7,684	7,772	7,683	7,755
Residential Lighting	7	7	7	7
Total Base Residential Deliveries	7,691	7,779	7,690	7,763
Total Net Residential Deliveries[5]	7,691	7,779	7,674	7,631

1 weather adjusted
2 includes actual weather adjusted deliveries through December 2009
3 base forecast (B)
4 base forecast (B)
5 adjusted for price elasticity and incremental EE and AMI impacts (M)

Commercial Deliveries Forecast by NAICS Cluster

(At average weather)

Net of Price Elasticity, PGE Energy Efficiency and AMI [1]

	(In million kWh)				% Change [1]		
	2008	2009 [2]	2010 [3]	2011 [4]	2009	2010[3]	2011[4]
Food Stores	486	485	474	470	(0.1%)	(2.4%)	(0.8%)
Govt. & Education	1,025	1,023	1,013	1,016	(0.2%)	(1.0%)	0.3%
Health Services	679	710	711	717	4.5%	0.2%	0.8%
Lodging	106	104	102	103	(1.6%)	(2.2%)	0.5%
Misc. Commercial	738	669	673	672	(9.4%)	0.7%	(0.1%)
Department Stores/Malls	352	348	353	362	(1.3%)	1.5%	2.3%
Office & F.I.R.E [5]	1,030	1,037	988	982	0.6%	(4.7%)	(0.7%)
Other Services	827	820	813	819	(0.9%)	(0.8%)	0.6%
Other Trade	811	775	783	789	(4.5%)	1.1%	0.7%
Restaurants	464	469	462	460	1.0%	(1.5%)	(0.2%)
Trans., Comm. & Utility	674	656	669	681	(2.6%)	1.9%	1.8%
Total Commercial	7,192	7,095	7,041	7,069	(1.3%)	(0.8%)	0.4%

[1] calculated from un-rounded numbers
[2] includes actual weather-adjusted deliveries through December 2009
[3] price elasticity, incremental EE and AMI adjusted forecast
[4] price elasticity, incremental EE and AMI adjusted forecast
[5] Finance, Insurance and Real Estate

Industrial Deliveries Forecast by NAICS Cluster

(At average weather)

Net of Price Elasticity, PGE Energy Efficiency and AMI [1]

	(In million kWh)				% Change [1]		
	2008	2009 [2]	2010 [3]	2011 [4]	2009	2010[3]	2011[4]
Food & Kindred Products	214	211	204	200	(1.1%)	(3.7%)	(1.7%)
High Tech	1,680	1,755	1,953	1,917	4.5%	11.3%	(1.9%)
Lumber & Wood	115	100	101	101	(13.4%)	1.1%	(0.4%)
Primary & Fab. Metals	552	453	473	504	(17.9%)	4.5%	6.4%
Other Manufacturing	625	577	609	614	(7.7%)	5.6%	0.8%
Paper & Allied Products	1,230	856	753	798	(30.4%)	(12.1%)	6.0%
Transportation Equipment	198	191	185	187	(3.2%)	(3.5%)	1.5%
Total Manufacturing	4,613	4,144	4,278	4,320	(10.2%)	3.2%	1.0%

[1] calculated from un-rounded numbers
[2] includes actual deliveries through December 2009
[3] p price elasticity, incremental EE and AMI adjusted forecast
[4] price elasticity, incremental EE and AMI adjusted forecast

Forecast of Deliveries under Miscellaneous Secondary Rate Schedules

Net of Price Elasticity, PGE Energy Efficiency and AMI

	(In million kWh)				% Change[1]		
	2008	2009[2]	2010	2011[3]	2009	2010	2011[2]
Secondary (Residential)							
Outdoor Area Lighting [4]	7.0	6.9	7.1	7.1	(0.4%)	2.0%	1.0%
Secondary (Commercial)							
Outdoor Area Lighting [4]	16.7	16.7	16.9	17.0	0.1%	1.1%	1.0%
Farm Irrigation et al. [6]	86.4	84.2	90.4	91.6	(2.5%)	7.3%	1.3%
Street and Other Lighting [7]	109.9	110.7	112.6	114.2	0.7%	1.8%	1.4%
Total Misc. Commercial	212.9	211.5	219.9	222.8	(0.6%)	4.0%	1.3%
All Misc. Schedules [8]	219.9	218.5	227.0	230.0	(0.6%)	3.9%	1.3%

[1] calculated from un-rounded numbers
[2] includes actual deliveries through December 2009
[3] identical for base, post price-effect, post-EE and post-AMI forecasts
[4] existing Schedule 15R
[5] existing Schedules 15C
[6] existing Schedules 47 & 49
[7] existing Schedules 91, 92 & 93
[8] equals Outdoor Area Lighting + Total Misc. Commercial

Total Delivery and Demand Forecast

Net of Price Elasticity, Incremental Energy Efficiency, and AMI

(At average weather)

	Million kWh[1]	Average MW[2]	Peak MW[3]
2008	19,709	2,394	4,031
2009	19,230	2,316	3,949
2010[4]	19,212	2,359	3,765
2011[5]	19,243	2,362	3,770

1 cycle-month basis, at end-user meters; includes actual deliveries through December 2009
2 calendar basis, delivered to PGE's distribution system weather-adjusted history to December 2009
3 coincidental annual system peak; includes actual through December 2009, not adjusted for weather
4 price elasticity, incremental EE and AMI adjusted forecast
5 price elasticity, incremental EE and AMI adjusted forecast

Forecast of 2011 Deliveries to Cost of Service and Non-Cost-of-Service Customers

Net of Price Elasticity, Incremental Energy Efficiency and AMI

(In million kWh)

	Cost of Service	Non-Cost of Service[1]	Total Delivery[2]
Residential	7,630.8	0.0	7,630.8
Secondary	7,378.3	39.0	7,417.3
Primary	2,905.4	177.7	3,083.1
Transmission	500.7	496.7	997.4
Lighting	114.2	0.0	114.2
Total Retail	18,529.4	713.4	19,242.8

1 Schedule 483/489 deliveries including variable price option (index power) purchases
2 totals may not add up due to rounding

Table of Contents

I. Introduction and Summary

Q. Please state your names and positions.

A. My name is Doug Kuns. I am the Manager of the Pricing and Tariffs Department within the Rates and Regulatory Affairs Department. My qualifications are described in Section V.

My name is Marc Cody. I am a Senior Analyst in the Pricing and Tariffs Department. My qualifications are described in Section V.

Q. What is the purpose of your testimony?

A. This testimony and accompanying exhibits demonstrate how our proposed E-18 Tariff changes recover PGE's 2011 revenue requirement in a way that achieves just and reasonable prices for all our customers. In addition to estimating the overall effect on customer bills, this testimony also describes the Marginal Cost Study, the revenue requirement allocation process, and the rate design.

Q. Has PGE been working with stakeholders regarding marginal cost and ratespread issues since UE 197?

A. Yes. As a result of a stipulation in UE 197, the Commission opened a docket (UM 1415) to address these issues. Workshops have been held and PGE has actively engaged in these workshops.

Q. Do the Marginal Cost Study and the revenue allocations incorporate the principles you outlined during the UM 1415 workshops?

A. Yes. We propose to allocate the functional revenue requirements in the same manner as we outlined during the final UM 1415 workshop of January 8, 2010.

Q. Please summarize the projected Cost of Service rate impacts resulting from the proposed allocations.

A. Table 1 below summarizes the base rate impacts of our proposals for the major rate schedules.

Table 1
Estimated Cost of Service Rate Impacts

	Estimated Rate Change (%) (base rates)
Schedule 7 Residential	8.8%
Schedule 32 Small Nonresidential	8.2%
Schedule 83 31-200 kW	9.3%
Schedule 85 201-1,000 kW	5.8%
Schedule 89 Over 1,000 kW	2.2%
COS Overall	7.3%

Q. Please summarize the methodological changes in marginal cost estimation, ratespread, and rate design you have made from the methods used in UE 197.

A. The key changes we propose are listed below (and explained in our testimony):

- Allocate the generation revenue requirement based on long-run marginal costs rather than the short-run methodology employed in previous dockets.
- Evaluate and modify the allocation of customer costs that comprise the functional Metering, Billing, and Other Consumer categories. This includes a separate allocation of uncollectible expense to the individual rate schedules.
- Create a new rate schedule, Schedule 85, for customers between 201 and 1,000 kW facility capacity.
- Change the Schedule 7 Residential Service blocking from two blocks with a breakpoint of 250 kWh monthly to three blocks with breakpoints at 500 and 1,000 kWh monthly. We also propose a slightly more steeply inclined block rate structure.
- Propose various rate design changes that are discussed further in the appropriate section of testimony.

- Create new schedules and change existing ones. Most of the changes to existing schedules are to accommodate the creation of Schedule 85 and are housekeeping in nature.

Q. Do you propose new supplemental schedules in this filing?

A. Yes. We introduce a new Schedule 145 that proposes to incorporate potential changes in end-of-life assumptions related to the Boardman coal plant. We also propose Schedule 141 that adjusts annually the revenue requirement associated with pension expense and financing costs related to cash contributions to the pension fund. If approved, both Schedules 145 and 141 start with zero prices. We further discuss these schedules later in testimony.

Q. Do you propose changes to existing supplemental schedules or to Schedule 300?

A. Yes. We propose to set Schedule 111 Advanced Metering Infrastructure and Schedule 121 Selective Water Withdrawal Adjustment prices to zero effective January 1, 2011, consistent with the provisions of the schedules.

We propose some language changes to Schedule 123, the Sales Normalization Adjustment. We also propose some language changes to Schedule 126 consistent with the testimony contained in PGE Exhibit 200. Additionally, we propose a language change to Schedule 125 to accommodate a modeling change to thermal plant variable O&M that is discussed in PGE Exhibit 400.

Finally, we also propose to increase the Schedule 300 charges for Standard and Enhanced Temporary Service. The Pricing Work Papers contain the basis for the Temporary Service price changes.

II. Marginal Cost of Service Study and Ratespread

Q. Briefly describe the purpose of a Marginal Cost of Service Study.

A. Since the mid-1970s, Oregon utilities have developed marginal cost studies for a number of purposes. In this case, PGE uses its Marginal Cost of Service Study to guide the allocation of the generation, distribution, and customer service (separately, Metering, Billing, and Other Consumer Service) functional revenue requirements in the rate spread process. The results of the distribution and customer service portions of this study are summarized in Table 8 of PGE Exhibit 1505. The generation portion is summarized in PGE Exhibit 1504.

Q. What other functional revenue requirement categories do you allocate besides those mentioned above?

A. Because the Ancillary Services revenue requirement is split out from generation, we allocate it in the same manner as we do generation. We also allocate the transmission revenue requirement in accordance with the generation allocation. These two functional categories combined with the five categories above complete the seven functional categories specified in Senate Bill 1149 enacted in 2002.

Q. Why do you allocate transmission revenue requirements in the same manner as you do generation?

A. Generally, we have previously allocated transmission revenue requirements on a peak load basis. The 1992 NARUC Cost Allocation Manual lends support to this on page 128: "For purposes of a marginal cost study, investment in the transmission system is generally assumed to be driven by increments in system peak load."

However, in this docket, we allocate transmission revenue requirements consistent with long-term generation marginal costs. We do so because PGE's 2009 Integrated Resource

Plan (IRP) proposes two large transmission projects, Cascade Crossing and South of Allston that interconnect existing PGE generation resources as well as new gas and wind resources.

Q. Please describe the analysis you performed regarding the allocation of these two transmission projects.

A. We first designated the South of Allston project entirely as capacity because it will integrate a new peaking resource of up to 200 MW as well as integrate the Beaver capacity of 181 MW that is not integrated from the Port Westward to Trojan line. The Cascade Crossing project will integrate Boardman, Coyote, a new 450 MW combined cycle baseload gas plant, and approximately 600 MW of new wind resources. Consistent with our generation marginal cost study, we designate all but the wind resources as 31% capacity, 69% energy. We designate the wind resources as 100% energy. We then allocate the nameplate capacity of all the existing and proposed resources in the manner described above. The result for the two transmission projects is an allocation of approximately 35% to capacity and 65% to energy.

Q. Did you allocate the two projects on the basis of capital expenditures?

A. Yes. We used the same capacity/energy designations for each generation resource above to allocate the estimated $45 million South of Allston project costs and the estimated $823 million (both projects in 2009 dollars) Cascade Crossing project costs. The result of this allocation was approximately 24% to capacity and 76% to energy. The Pricing work papers contain the two aforementioned analyses.

Q. How do these two analyses support the transmission allocation based on generation?

A. We used the generation cost allocation for transmission revenue requirements because the simple average of these two analyses approximates the test period generation cost allocation of 31% capacity/69% energy. The details of the two analyses are contained in the Pricing work papers.

Q. Do you allocate other cost categories to the individual rate schedules?

A. Yes. We allocate franchise fees and OPUC fees on a current revenue basis and Trojan decommissioning on a busbar energy basis. We allocate Schedule 129 Long-Term Transition Adjustment to Schedule 85 and 89 customers on an energy basis, and finally, we allocate uncollectible expense based on historical incidence for the years 2006-2008. This latter category was previously not specifically allocated, but was treated as a revenue sensitive cost, and was therefore implicitly allocated to schedules on a revenue basis. All allocations are presented in PGE Exhibit 1504.

Q. Do you propose any form of rate mitigation or other deviation from using marginal cost to spread the revenue requirements?

A. No, however, we employ the Customer Impact Offset (CIO) <u>after</u> spreading the revenue requirements in order to temper the rate impacts to certain schedules. Specifically, we limit the rate increase to two times the average increase for Schedules 38, 47, 49, and 93. We further limit the subsidy to no more than 9.5 cents/kWh. For our major cost of service rate schedules (7, 32, 83, 85, and 89) we limit the increase to 1.25 times the average increase. Additionally, before calculating the increase limit discussed above, we set a floor such that no rate schedule receives a decrease. When allocating the CIO we do not propose any surcharges for schedules 7, 32, and 83 because for these schedules we propose increases that are above the average increase. We further discuss the CIO later in this testimony.

Q. Could you please provide a brief history of how PGE has previously estimated its marginal cost of generation?

A. Prior to this docket, PGE has used the same short-run marginal cost methodology since UM 827 (1997). PGE stated at that time the following:

> PGE's Avoided Cost Study, which was approved by the Commission and became effective on December 18, 1996, serves as the foundation for determining marginal generation costs. In this study, the combined effect of a significant reserve margin in the 11-state WSCC and an increasingly vibrant market for electricity was observed to drive the cost of short-term firm power below the cost of a new, long-term generating resource and below the fully allocated cost of existing resources. We expect this trend, and its effect on short-term prices, to remain for the foreseeable future. Moreover, this trend has significantly reduced the cost of capacity, which is reflected now primarily through the differential between on-peak and off-peak energy prices.

Q. Please continue.

A. When we filed UE 115 in 2000 we used the same short-run methodology. At that time we did not contemplate new generation resources, in particular given that the UE 115 docket was largely about restructuring to accommodate direct access and portfolio options consistent with the requirements contained in Senate Bill 1149. At that time no one objected to the short-run marginal cost approach and we subsequently settled on a generation allocation methodology. This methodology specified historical resource shares of existing assets accompanied by allocations of BPA Subscription Power as part of a resource stacking methodology.

In UE 180, which we filed in March of 2006, we proposed once again the same marginal cost methodology, thereby eliminating the historical generation allocations stipulated to in UE 115. In UE 180, the methodology was opposed solely by ICNU in its direct testimony. Prior to PGE filing its rebuttal testimony, parties settled ratespread and rate design issues. The outcome of this settlement was the adoption of the PGE proposed marginal cost and generation allocation methodology.

Q. Please describe the positions of parties in UE 197.

A. In UE 197, PGE proposed the same short-run marginal cost of generation methodology as in the prior dockets. ICNU raised issues with this methodology relating to the lack of consideration of capacity costs and reliability planning. Staff in Staff Exhibit 600 stated that they recommend adoption of PGE's marginal cost study because it provides reasonable results. However, on page 6, line 18 to page 7, line 2 Staff stated the following: "regarding production marginal costs it seems reasonable to use potential new electrical generating plants as the basis for capacity and energy costs instead of relying exclusively on wholesale market energy prices." Staff in Staff Exhibit 1200 then stated a preference to use the generation marginal cost as filed by PGE in its direct testimony. CUB in their surrebuttal testimony supported using the short-run methodology proposed by PGE in its direct testimony.

Q. What methodology do you propose in this docket?

A. We propose a long-run generation methodology that explicitly takes into account the cost of marginal generation capacity and long-run marginal energy costs. This marginal cost methodology is consistent with our IRP that identifies a need for capacity resources for both the winter and summer periods. This methodology is similar to the long-run methodology we proposed as an alternative in our UE 197 Rebuttal testimony. It is also the methodology we proposed during the UM 1415 workshops.

Q. Please describe the steps you used to develop the long-run generation allocation methodology.

A. The generation marginal cost analysis involves the following inputs and steps:

1. Determine both a long-run marginal energy cost and a long-run marginal capacity cost by first defining the marginal long-run generation resource as a combined cycle combustion turbine (CCCT) used for baseload purposes.

2. From this analysis, separately estimate the capacity and energy components as follows:

    a) Estimate the marginal cost of future capacity as the fixed cost of a simple cycle combustion turbine (SCCT).

    b) Use these SCCT fixed costs as the portion of the CCCT fixed cost that is assigned to capacity with the remaining CCCT fixed costs assigned to energy.

    c) To the SCCT capacity costs add 12% reserve requirements consistent with PGE's 2009 IRP.

3. Finally, express these capacity and energy values in real levelized terms. PGE Exhibit 1504 presents the summary of these long-run marginal capacity and energy cost calculations. PGE Exhibit 1504 also presents the results of how the generation revenue requirement is spread to the rate schedules.

Q. How did you calculate the 2011 test-period marginal capacity costs?

A. We multiplied the real levelized annual capacity cost described above by the projected 2011 test-period peak hour load. This peak hour load is projected to occur in January.

Q. How did you allocate the marginal capacity costs to each rate schedule?

A. We allocated the total 2011 test period marginal capacity costs described above on the basis of each schedules' relative contribution to the monthly peak hours contained in the months of January, July, August, and December (4-CP).

Q. Why did you choose these four monthly peaks?

A. We chose these four months because they are the months with the highest peaks consistent with the periods identified as capacity deficient in the 2009 IRP. We additionally chose these months because for each of the past ten years PGE's highest annual peak hour occurred during one of these four months.

Q. How did you estimate the marginal energy costs?

A. We used both the long-run real levelized marginal energy cost derived from our analysis described above and the projected fully allocated cost of a generic wind farm as identified in the IRP.

Q. Please describe how you determined the proportion of marginal energy costs attributable to the CCCT and the generic wind farm.

A. We used the proportion of new gas and renewable resources proposed for the year 2020 as identified on page 320 of the IRP. This resulted in an attribution of 58% of marginal energy costs to the energy costs of a CCCT as defined above, and 42% to the fully allocated costs of a generic wind farm.

Q. What is the source of your long-term gas price forecast?

A. We used the long-term gas price forecast contained in our IRP for the Sumas and AECO hubs. We equally weighted the projected burnertip prices from these two hubs.

Q. Did you include the projected costs of carbon dioxide compliance in your analysis?

A. Yes. We include compliance costs of $30.00 per short ton (real levelized 2009$) consistent with the environmental assumptions in the IRP.

Q. What is the fully allocated cost of a generic wind farm as specified in the IRP?

A. On page 118 of the draft IRP issued September 4, 2009, a fully allocated wind farm is estimated at $93.62/MWh in real levelized 2011 dollars.

Q. Did you modify this real levelized figure for purposes of the marginal cost study?

A. Yes. Because of the two large transmission projects proposed in our IRP, we removed the wheeling portion of estimated costs to be consistent with how we modeled the fully allocated costs of a CCCT and the capacity costs of a SCCT. This results in a real levelized marginal energy cost for wind of $85.69/MWh.

Q. How did you shape these energy costs into hourly values?

A. We shaped the weighted marginal energy costs described above into hourly intervals based on the energy price shaping from PGE's production cost model, Monet.

Q. How did you estimate each rate schedule's marginal energy cost?

A. We performed the following steps to calculate the 2011 hourly load profile and marginal energy cost of each rate schedule:

1. For each schedule and each month, calculate a typical weekday, Saturday, and Sunday load shape using 2008 hourly load profiles.
2. Use these day-type hourly profiles and the projected monthly peak hour loads to shape each schedule's monthly test-period load forecast into hourly values.
3. By hour, sum each schedule's loads from 2 above and compare these hourly sums to the hourly system load forecast. Assign hourly differences between the two quantities on the basis of each schedules monthly standard deviation of hourly shaped loads in 2 above. These standard deviations are differentiated by weekday, Saturday, and Sunday.
4. Multiply each schedule's shaped hourly load forecast by the corresponding hourly long-term energy cost described above.

Q. How does this projection of hourly interval loads compare to the monthly load forecast submitted in this docket?

A. The energy values by schedule match precisely. However, by inserting the projected monthly peak hour loads to smoothed hourly loads, the monthly peak load hours and the hourly loads immediately proximate to the peak load hours can sometimes appear to be somewhat less than smooth. Nevertheless, the hourly interval data yields a more granular basis to allocate the marginal cost of energy relative to simply using monthly energy values and monthly loads. It furthermore is responsive to those parties in the UM 1415 workshops that stated a preference for hourly marginal energy cost estimation.

Q. Did you use the shaped hourly loads for any purpose other than for the marginal cost of energy?

A. Yes. We used the hourly loads to calculate the annual non-coincident peak load factors for the individual rate schedules. With one exception, Schedule 38, we used the calculated load factors because they provided reasonable values relative to what we have used in previous dockets. For Schedule 38 we imposed a non-coincident peak load factor of 20%, consistent with past practice. This 20% load factor approximates the load factor that results in comparable monthly bills for both Schedules 38 and 83.

Q. Please summarize how you calculate marginal distribution costs.

A. We separately calculate marginal distribution costs for subtransmission, substations, distribution feeders (backbone facilities and local facilities), line transformers and 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 projected capital expenditures over the five-year period 2010-2014. We then annualize these capital expenditures and divide by the growth in system non-coincident peak. Customers served at subtransmission voltage are not included in the substation calculation because they supply their own substation.

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 network feeders that serve downtown core areas.
3. Perform an inventory of the wire types and sizes for each feeder. Standardize these wire types and sizes to current specifications and then calculate the cost of rebuilding these feeders in today's dollars.
4. Segregate the wire types and sizes into mainline feeders and taplines. Mainline feeders are typically capable of carrying larger loads and are generally closer to the substations from which they originate. Taplines are typically capable of carrying smaller loads and can be remote from substations.
5. For each feeder, allocate the mainline cost responsibility of each rate schedule based on the rate schedule's proportionate contribution to 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 (distribution design standard peak load). Calculate a unit cost per kW for both poly and single phase customers by totaling the feeder cost responsibilities and dividing by the sum of each schedule's design demand.
7. Annualize the mainline and tapline unit costs by applying an economic carrying charge.

8. Separately estimate the unit costs of customers greater than 4 MW who are typically on dedicated distribution feeders. Calculate these marginal unit costs (per customer) as the average distance between the substation and the customer-owned facilities. Because new customers on dedicated circuits typically have a redundant feeder, multiply this average distance by two, resulting in a per-customer average of 10,800 feet of dedicated feeders. Finally, apply the annual carrying charge to annualize the cost per customer.
9. Separately estimate the per customer cost of customers served at subtransmission voltage by first calculating the average distance from the point at which subtransmission voltage customers connect into the subtransmission system from their substation and then multiplying this average distance by the current cost per wire mile. These estimated costs are then annualized.

Q. Please describe any other considerations in calculating unit feeder costs.

A. Currently, many municipalities require undergrounding of taplines within subdivisions and commercial areas. We therefore 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 their service and transformer costs. Table 4 of PGE Exhibit 1505 summarizes these marginal transformer and service costs by schedule.

Q. Why have you moved the service and transformer costs to the "customer" category within Distribution?

A. We moved this category to the customer category from the "facilities" category because we believe that it is more appropriate to group these one-time hookup costs with customer-related costs such as meters. As in both UE 180 and in UE 197, the applicable determinant for both services and transformers is number of customers, or, in the case of transformers, number of customers on a transformer. Therefore, it makes sense to reclassify these distribution costs to "customer."

Q. Please describe how you calculate the marginal costs of meters.

A. We calculate marginal meter costs as the newly installed costs of providing AMI meters for each customer and then apply an annual carrying charge. Table 5 of PGE Exhibit 1505 summarizes the marginal costs of meters.

Q. How do you allocate distribution O&M to each distribution category and ultimately to each rate schedule?

A. We allocate test-period distribution O&M by distribution category to the rate schedules in proportion to each schedule's respective usage times its marginal capital cost. Table 6 of PGE Exhibit 1505 provides the details of this allocation and the final distribution marginal costs by distribution category.

Q. How do you calculate the marginal costs of Metering?

A. We calculate the marginal cost of the limited amount of meter reading expected to occur in 2011 based on a historical meter reading study. This study measures the average time per rate schedule it takes to read meters including transport time. For the Network Data Operations O&M, we use the number of customers less street and area lighting customers. For the Meter Services portion of metering O&M, we allocate the costs in the following manner: 20% to residential customers, 75% to nonresidential customers, and 5% as credit-related. Finally, we allocate the remaining Metering O&M costs based on a sub-allocation of the above allocations. We then divide the 2011 allocated amounts by projected 2011 customer counts to derive the marginal Metering cost per customer for each rate schedule.

Q. How do you calculate the marginal costs of Billing?

A. We allocate the collection-related cost ledgers on the same basis as the uncollectible accounts. We allocate some of the cost ledgers directly on the basis of cost-causation and we allocate some of the other support ledgers such as technology maintenance support based on sub-allocations of the other accounts within Billing. After we allocate the various Billing O&M ledgers, we divide the total allocations by the projected 2011 customer counts by schedule. This result is the Billing marginal cost for each rate schedule.

Q. How do you calculate the marginal costs of Other Consumer Service?

A. We calculate the marginal cost of Other Consumer Service by allocating the individual cost ledgers to the rate schedules based on various cost-causation principles. For example, we allocate the ledger titled “Phone Response to Residential Account Inquiries” entirely to residential customers. We allocate Commercial/Industrial Account Management to the applicable customers based on a weighting of 20% applicable customer count and 80% energy consumption. As with Billing, we allocate certain support cost ledgers based on sub-allocations within the functional category. After we allocate the individual cost ledgers to the individual rate schedules we divide the allocations by the test period customer count to obtain a per customer marginal cost. Table 7 of PGE Exhibit 1505 contains the summary of the marginal customer costs.

III. Rate Schedule Design

Q. Please provide a brief summary of the major Cost of Service Rate Schedules.

A. There are five major Cost of Service (COS) rate schedules:

Schedule 7, Residential Service, currently consists of a monthly Basic Charge, volumetric Transmission and Distribution Charges, and a two-block energy rate. As we discuss later in testimony we propose to implement a three-block energy rate.

Schedule 32, Small Nonresidential Standard Service, consists of a monthly Basic Charge, a volumetric Transmission Charge, and a two-block Distribution Charge. The Energy Charge is flat across all energy usage.

Schedule 83, Large Nonresidential Standard Service, is proposed to be applicable to all Large Nonresidential customers between 31 and 200 kW, except for certain specialty schedules. Because we have so few primary voltage customers below 200 kW, we restrict this schedule to secondary service only. This schedule contains more complex charges than Schedules 7 and 32. In addition to the customer charges, there is a Transmission Demand Charge based on the highest metered kilowatt (kW) reading for a 30 minute period during the monthly billing cycle. There is also a Distribution Demand Charge based on the same criteria above, and a Distribution Facility Capacity Charge based on the average of the two greatest monthly Demands within a 12-month period (Facility Capacity). The Energy Charge is flat for all energy usage.

Schedule 85, Large Nonresidential Service (201 to 1,000 kW) Standard Service, is a proposed new schedule. We propose this new schedule for the following reasons:

1) The creation of the schedule allows for a more equitable allocation of the Schedule 129 transition adjustment. Previously this transition adjustment amount was

allocated to many Schedule 83 customers that were not eligible for the multi-year option that creates the transition adjustment amounts.

2) Partitioning the current Schedule 83 into two rate schedules allows for improved cost allocation. For example, the larger customers within the current Schedule 83 incur higher customer-related costs such as representation by the Key Customer Management (KCM) Group. Generally the 200 kW demand threshold is where customers are more likely to be assigned to a KCM representative and also where PGE installs more expensive reactive demand (kVar) metering capability. Therefore it makes sense to evaluate other cost differences such as generation and distribution costs for customers above 200 kW.

The pricing for Schedule 85 retains many of the same features as Schedule 83, but we differentiate the energy charge by on and off-peak periods similar to Schedule 89. We base the Transmission and Distribution Demand Charges on the 30-minute peak periods occurring during on-peak intervals.

Schedule 89, Large Nonresidential (>1,000 kW) Standard Service, is a schedule for customers whose Facility Capacity exceeds 1,000 kW. This schedule contains Transmission and Distribution Demand Charges for which we continue to propose to charge only for 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 is calculated in the same manner as for Schedules 83 and 85. The Energy Charges will continue to be on- and off-peak differentiated.

Q. How did PGE develop the prices for each rate schedule?

A. We explain the development of the prices for each of the major rate schedules below. PGE Exhibit 1503, Rate Design, provides additional detail regarding how the individual prices for each schedule were designed.

Q. Please list the individual prices for Schedule 7, Residential Service.

A. The prices are summarized below:

Schedule 7
Residential Service Proposed Prices

Category	Prices
Basic Charge Single Phase	$10.00 per customer per month
Basic Charge Three Phase	$14.00 per customer per month
Transmission & Related Service Charge	2.43 mills per kWh
Distribution Charge	33.49 mills per kWh
Energy Charge First 500 kWh	59.00 mills per kWh
Energy Charge Next 500 kWh	76.43 mills per kWh
Energy Charge Over 1,000 kWh	84.00 mills per kWh

Q. Please explain how you developed these prices.

A. Although the Marginal Cost Study results suggest a **Basic Charge** of approximately $18.50, we propose to maintain the single-phase charge at $10.00. We propose to increase the three-phase Basic Charge to $14.00 based on the percent of single-phase costs recovered from the $10.00 single-phase Basic Charge. For both Schedule 7 and Schedule 32 we propose to remove the Nonstandard Metering Charge that is applicable to the Time-of-Use (TOU) Portfolio Option.

We develop the **Transmission & Related Service Charge** directly from the allocated transmission and ancillary services revenue requirement.

We calculate the **Distribution Charge** of 33.49 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 and OPUC fees and Trojan Decommissioning costs.

We developed the Schedule 7 blocked **Energy Charges** based on the following subjective criteria:

1. The price increase should approximate the overall base rate increase of 7.4% for customers who consume up to 1,000 kWh monthly, the breakpoint for the second and third blocks.
2. For Schedule 7 customers who consume 2,000 kWh monthly, the base rate increase should be approximately 1.5 times the Schedule 7 base rate increase of 8.8%. This helps to ensure that less than 20% of residential customers will see an increase exceeding 1.5 times the residential average during the peak consumption month of January.
3. Adjust the first and second block prices as necessary to mitigate the percent changes of those customers impacted by the change in block size from 250 kWh to 500 kWh.

Q. What is the base rate change for an average residential customer consuming 900 kWh monthly after applying the criteria above?

A. The base rate change for a Schedule 7 customer consuming 900 kWh is 6.7%. Including all supplemental schedules, the change is 7.0%. PGE Exhibit 1502 provides the rate impacts at various consumption levels. These rate impacts are with all supplemental schedules, including the Schedule 108 Public Purpose Charge (PPC) and the Schedule 115 Low Income Adjustment.

Q. What is the current energy pricing structure based upon?

A. The current block of 250 kWh is an anachronism from UE 115. In that docket, we stipulated to this block level in order to approximate the residential share of BPA Subscription Power deliveries. We have not received Subscription Power since September 2006. The current difference of 1.775 cents/kWh between the blocks is a holdover from UE 180. In that docket, parties stipulated to a price differential of at least 1.75 cents/kWh between the first and second blocks while maintaining the UE 115 blocking at 250 kWh.

Q. What is the basis of kWh blocking you propose in this case?

A. The first block of 0-500 kWh monthly approximates a baseline level of usage, therefore a level of usage without space conditioning or electric hot water heating for a three bedroom dwelling unit. We base this statement on estimates contained in the Housing Choice Program Guidebook provided by the U.S. Housing and Urban Development. This first block also allows us to better manage the rate impacts for those customers consuming less than 1,000 kWh monthly. We estimate that about 50% of the Schedule 7 annual consumption will be priced at the first block and about 30% of the Schedule 7 consumption will be priced at the higher second block of 501-1,000 kWh monthly.

Based on 2009 historical data, approximately 28% of Schedule 7 bills are for less than 500 kWh monthly and approximately 67% are for less than 1,000 kWh monthly.

Q. Did you consider other Schedule 7 rate designs?

A. Yes. UM 1415 discussions included suggestions for other designs such as two blocks with a breakpoint at 1,000 kWh and the tailblock priced at long-run marginal cost (approximately 100 mills/kWh). We are open to other Schedule 7 rate designs, but customer impacts must be considered.

Q. Please comment on why you did not price the tailblock significantly higher than the other blocks.

A. We prefer to implement a more inclining block structure in a gradual manner, one that does not produce significantly higher impacts for larger users immediately. Our proposed rate design accomplishes this gradualism. In addition, large users comprise a significant portion of past-due accounts. Gradualism helps to limit growth in uncollectible amounts and helps us learn about customer responses to pricing changes.

Q. Please list the individual prices for Schedule 32, Small Nonresidential Service.

A. The prices are summarized below:

Schedule 32
Small Nonresidential Service

Category	Price
Basic Charge Single Phase	$12.00 per customer per month
Basic Charge Three Phase	$16.00 per customer per month
Transmission & Related Services Charge	2.28 mills per kWh
Distribution Charge First 5,000 kWh	35.41 mills per kWh
Distribution Charge Over 5,000 kWh	8.17 mills per kWh
Energy Charge	64.87 mills per kWh

Q. Please describe how you developed the Schedule 32 prices.

A. Schedules 32 and 532 apply to Small Nonresidential customers, whose Facility Capacity is less than 30 kW. Schedule 532 (applicable to Direct Access Service) is actually a subset of Schedule 32 in that it contains some, but not all, of the cost components of Schedule 32. Small Nonresidential customers receive service at secondary voltage and other than the Basic Charge, all charges are expressed as a volumetric kWh charge. As with Schedule 7, the applicable costs are allocated into the Basic, Transmission, Distribution and Energy Charge categories. We maintain the **Basic Charge** for single- and three-phase service at $12 and $16 per month, which are considerably below the marginal customer-related costs. As with Schedule 7, we capture the difference between the allocated costs and the various revenues within the Distribution Charge.

We compute the **Transmission and Related Services Charge** directly from the allocated transmission and ancillary service costs.

We retain the current Schedule 32, **Distribution Charge** blocking, with the initial block including usage up to 5,000 kWh. We set the second block for usage greater than 5,000 kWh on a declining basis to 5.00 mills per kWh (prior to adding the System Usage Charge) in order to provide a transition to Schedule 83 for customers whose loads have exceeded 30 kW at least twice during the preceding 13 months. We set this tailblock rate at a higher level than in UE 197 consistent with the increased price for the first block. The design provides effective rate migration for customers who migrate from volumetric-based distribution pricing to demand-based distribution pricing (Schedule 32 to 83). Similar to Schedule 7, we include within the Distribution Charge the costs associated with franchise and OPUC fees and Trojan Decommissioning.

We set the **Energy Charge** on a flat year-round basis that is based on the allocation of generation costs.

Q. 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. We incorporate a Daily Price Energy Charge into Schedule 32 in order to address the potential cost impact of customers switching from Schedule 532 to Schedule 32 prior to completing at least one year of service on Schedule 532. The daily price tracks the daily market price for power and is based on the secondary voltage Daily Price option in Schedule 83.

Q. Please provide the proposed prices for Schedule 83 and describe the customers to whom these prices apply.

A. Schedule 83 applies to all Nonresidential customers with Facility Capacity loads greater than 30 kW and less than or equal to 200 kW. Those customers whose load exceeds 200 kW will take service under Schedule 85, which we discuss below. We use the same approach and cost causation principles as described for Residential and Small Nonresidential service in designing these rates.

The Schedule 83 charges include more detail because Large Nonresidential customers are generally more sophisticated energy users and are more able to react to pricing signals triggered by their peak consumption. Schedule 83 is for secondary delivery voltage only. We limit this to secondary voltage in order to reduce the administrative burden of separately maintaining an option for only about 20 accounts below 200 kW that are served at primary voltage. We propose that these 20 accounts be billed at Schedule 83 prices, after applying the 1.5% adjustment to meter data as specified in Rule M-4. The proposed prices are below:

Schedule 83
General Service 31-200 kW

Category	Monthly Price
Basic Charge Single Phase	$20.00 per customer per month
Basic Charge Three Phase	$30.00 per customer per month
Trans. & Related Services	$ 0.88 per kW peak Demand
Distribution Demand Charge	$ 1.83 per kW peak Demand
Facility Capacity Charge (First 30 kW)	$ 3.00 per kW Facility Capacity
Facility Capacity Charge (Over 30 kW)	$ 2.50 per kW Facility Capacity
System Usage Charge	3.80 mills per kWh
COS Energy Charge	64.13 mills per kWh

Q. Please describe how you developed the Schedule 83 prices.

A. We maintain the Schedule 83 single-phase **Basic Charge** at $20.00 and increase the three-phase charge to $30.00. This pricing level helps enable a smoother 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, 85, and 89, we set the **Transmission & Related Service Charge** to $0.88 per kW consistent with the other secondary voltage customers served on Schedules 85 or 89. We do this to make the pricing more consistent for customers who choose Direct

Access Service under Schedules 583, 585 or 589. This charge results in more than a full recovery of Schedule 83 allocated costs, consequently we flow the over recovery through to the System Usage Charge.

The **Distribution Charges** for Schedule 83 consist of a **Demand Charge** and a **Facility Capacity Charge**. We recover the costs associated with the 13 kV system through the Facility Capacity Charge. We set the Facility Capacity Charge for the first 30 kW at a lower 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.

The **Demand Charge** of $1.83 recovers the allocated revenue requirement of substations and the 115 kV system.

Because several energy options are available to Schedules 83 and 583, we separately state the **System Usage Charge.** This charge recovers franchise and OPUC fees and Trojan Decommissioning costs, as well as any other costs not fully recovered by the other charges.

Q. Please describe the Schedule 83 Energy Charge options.

A. Schedule 83 customers may choose to receive energy either from PGE based on PGE's COS energy option or from PGE's market-based energy option. The market-based option available to Schedule 83 is daily pricing based on the prices for the Mid-Columbia hub as reported by the Dow Jones Mid-Columbia Daily On- and Off-Peak Firm Pricing Index (Dow Jones). We propose to eliminate the current monthly Fixed Price Option due to a lack of customer interest in this pricing option. Customers may also choose to receive service from an ESS.

We propose that customers receiving service from an ESS or from a PGE market option continue to receive the Schedule 128, Short-Term Transition Adjustment in the same manner as they currently do.

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 1,000 kW. Those customers whose facility capacity exceeds 1,000 kW take service under Schedule 89 which we discuss below. We base the individual charges on the results of the marginal cost study and subsequent ratespread, paying particular attention to appropriately pricing the cost differentials between secondary and primary delivery voltages. The prices differentiated by delivery voltage are below:

Schedule 85 General Service 201-1,000 kW

Category	Secondary Price	Primary Price
Basic Charge	$400.00 per customer per month	$360.00 per customer per month
Trans. & Related Services	$ 0.88 per kW peak Demand	$ 0.85 per kW peak Demand
Distribution Demand Charge	$ 1.95 per kW peak Demand	$ 1.88 per kW peak Demand
Facility Capacity Charge (First 200 kW)	$ 2.04 per kW Facility Capacity	$ 1.97 per kW Facility Capacity
Facility Capacity Charge (Over 200 kW)	$ 2.04 per kW Facility Capacity	$ 1.97 per kW Facility Capacity
System Usage Charge	4.00 mills per kWh	3.86 mills per kWh
COS Energy Charge On-peak	65.39 mills per kWh	63.47 mills per kWh
COS Energy Charge Off-peak	53.60 mills per kWh	51.68 mills per kWh

Q. Please describe how you developed the Schedule 85 prices.

A. The Schedule 85 **Basic Charges** differ by delivery voltage. For secondary service and primary voltage, we set the Basic Charges at $400.00 and $360.00 per month respectively. These customer charges fully recover (subject to rounding) the allocated marginal customer-related costs. These customer charges combined with the flat facilities charge blocking provide a smooth transition for those Schedule 83 customers whose demand grows to exceed 200 kW. This pricing also provides for a better transition for those Schedule 85 customers whose demand exceeds 1,000 kW, thereby migrating to Schedule 89.

For Schedules 83, 85, and 89, we set the **Transmission & Related Service Charge** to $0.88 per kW for secondary service, and at $0.85 per kW for primary service, prices that are slightly higher than the allocated revenue requirements.

The **Distribution Charges** for Schedule 85 consist of a **Demand Charge** and a **Facility Capacity Charge**. For both secondary and primary voltage customers, we recover the costs associated with the 13 kV system through the Facility Capacity Charge. The difference between secondary and primary voltage Facility Capacity Charges reflect the difference in 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 $2.04 and $1.97 for secondary and primary customers respectively recover the allocated revenue requirement of substations and the 115 kV system. We calculate the demand charge difference based on the difference in peak demand losses of the respective delivery voltages.

Because several energy options are available to Schedules 85 and 585, we separately state the **System Usage Charge** which recovers franchise and OPUC fees, Trojan Decommissioning costs, the Schedule 129 transition adjustment, and the CIO. We also use this charge for both Schedules 85 and 89 to capture the Schedule 129 transition adjustment and the generation fixed cost contributions of either returning or departing long-term direct access customers.

We calculate the COS **Energy Charge** based on the results of the generation allocations. We use a 2011 projection of on- and off-peak differentiated Mid-Columbia forward curves to establish the time-differentiated energy charges. We calculate the energy price difference between the secondary and primary voltage customers based on the difference in embedded line losses. We believe that in the future, for both Schedules 85 and 89, we should move more towards pricing these differentials based on the losses of newly installed equipment rather than the embedded line losses. In this manner, customers will receive a more accurate price signal regarding PGE's marginal costs and a stronger incentive to purchase more energy-efficient transformers.

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 1,000 kW. Because of their unique characteristics we separately identify the distribution costs for customers whose loads exceed 4,000 kW and integrate these cost differences into the Schedule 89 pricing for service to secondary, primary, and subtransmission delivery voltages. The charges are based on the Marginal Cost Study with attention to billing impacts and the cost differentials between delivery voltages. The Schedule 89 prices differentiated by delivery voltage are below:

Schedule 89 General Service Greater than 1,000 kW

Category	Secondary	Primary	Subtransmission
Basic Charge	$1,310.00 per month	$1,040.00 per month	$2,020.00 per month
Transmission & Related Charge	$ 0.88 per on-peak kW	$0.85 per on-peak kW	$0.84 per on-peak kW
Facility Capacity Charge First 4,000 kW	$ 1.77 per kW Facility Capacity	$1.73 per kW Facility Capacity	$1.73 per kW Facility Capacity
Facility Capacity Charge Over 4,000 kW	$ 0.38 per kW Facility Capacity	$0.34 per kW Facility Capacity	$0.34 per kW Facility Capacity
Distribution Demand Charge	$ 2.05 per on-peak kW	$1.98 per on-peak kW	$0.91 per on-peak kW
System Usage Charge	4.27 mills per kWh	4.03 mills per kW	3.89 mills per kW
COS Energy Charge On-peak	63.24 mills per kWh	61.36 mills per kWh	60.54 mills per kWh
COS Energy Charge Off-peak	51.45 mills per kWh	49.57 mills per kWh	48.75 mills per kWh

Q. Please describe how you developed the Schedule 89 Charges.

A. We set the **Basic Charges** for secondary, primary and subtransmission voltage customers at approximately 90% of the marginal-customer-related costs with any under-collection captured by the Facility Capacity Charges. For customers served at subtransmission voltage this is an increase of $1,020 per month over the current monthly charge.

The Transmission and Related Service Charge is calculated in conjunction with Schedules 83 and 85 for the reasons previously discussed. Because this charge is less than the allocated costs, the Facility Capacity Charge recovers the remainder.

The **Distribution Demand Charge** for both secondary and primary voltage customers reflects the marginal cost of providing substations and shared subtransmission facilities. For customers served at subtransmission voltage who supply their own substation, the Distribution Demand Charge reflects the marginal cost of the shared subtransmission system. 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 seven cents/kW is added to the Distribution Demand Charge to equalize the Facility Capacity Charge for primary voltage and subtransmission voltage delivery. As with Schedule 85, we set the delivery voltage price differentials based on the peak demand loss differences of the respective delivery voltages.

The **Facility Capacity Charge** for Schedule 89 customers has two blocks; one for the first 4,000 kW, and the second for billing kW greater than 4,000 kW. Previously we blocked this schedule at 1,000 kW, but the proposed blocking is more reflective of distribution cost differences within the schedule. The first block facilitates the migration of customers from Schedules 85/585, while the second block captures the remaining facilities-related revenue requirements of Schedule 89 customers. Both Facility Capacity Charge blocks reflect the peak demand loss difference between providing service at secondary or primary voltage service. As mentioned above, we set the Facility Capacity Charge for subtransmission voltage customers equal to that of primary voltage customers and flow any cost difference to the subtransmission voltage Demand Charge.

The **COS Energy Charge** option for Schedule 89 is on- and off-peak differentiated by delivery voltage. 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.

Q. Describe the development of charges for the remaining rate schedules.

A. The remaining proposed rate schedules, with one exception, provide service to lighting and irrigation customers and are discussed below:

We structure **Schedule 15, Outdoor Area Lighting Standard Service**, charges in the same manner as the current rate schedule. The Monthly Charge contains all of the allocated costs based on the specific kWh usage by luminaire. Schedule 515 provides this customer class with Direct Access Service charges.

Schedule 38, Large Nonresidential Optional Time-of-Day Standard Service is, as its name implies, an optional schedule that is applicable to customers whose facility capacity is between 31 and 200 kW. We keep the monthly Basic Charges for single- and three-phase service at $20.00 and $25.00 dollars respectively. We maintain the volumetric recovery of transmission and distribution costs and continue to differentiate the energy charges based on the on- and off-peak periods defined in Schedule 38.

Schedule 47, Irrigation and Drainage Pumping Small Nonresidential Standard Service, applies to Small Nonresidential customers whose demand does not exceed 30 kW. We retain both the monthly Basic Charge at $25.00 per month for the six summer months only, and the blocked Distribution Charge. Schedule 47 customers may take Direct Access Service under Schedule 532.

Schedule 49, Irrigation and Drainage Pumping Large Nonresidential Standard Service, is similar to Schedule 47, but applies to customers larger than 30 kW. We retain the Basic Charge of $30 per month, summer months only. Similar to Schedule 47, we continue to block the Distribution Charge. Schedule 549 states the Direct Access charges for these customers. These customers are also eligible for Direct Access Service on Schedules 583 or 585.

Schedules 91/591, 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.

Schedule 92, Traffic Signals Standard Service, is an energy-only rate for un-metered traffic control devices in systems with at least 50 intersections. We retain the energy-only nature of the rate.

Schedule 592, Traffic Signals Direct Access Service, provides the Direct Access-related energy-only based charge for this specialty service. Schedules 92/592 remain grandfathered services closed to additional governmental agencies.

Schedule 93, Recreational Field Lighting Standard Service, rate design maintains the Basic Charge of $30 per month, with Distribution and Transmission Charges recovered on a volumetric basis.

Q. Please describe the Area and Streetlighting Cost of Service Study.

A. Streetlighting and Area Lighting prices include the costs of investment and maintenance in addition to the Transmission, Distribution and production-related charges that apply to all other schedules. We analyze the investment and maintenance costs components separately. For the investment component, we used the historical investment rates determined in UE 197 to estimate the total 2011 test-period investment revenue requirement. We estimate the maintenance component based on the expected cost of maintaining each type of lighting equipment and the frequency of maintenance.

PGE Exhibit 1506 summarizes the results of this study. This exhibit details the proposed energy charges, fixed charges, total charges, and total revenues for both Area and Street lighting.

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. This is also true, but to a lesser degree for Schedules 38 and 93. If we were to price these schedules at cost, they would experience significantly greater rate increases than average. This issue has existed for quite some time for Schedules 47 and 49, and our changes in marginal cost methodology and ratespread have considerably exacerbated the issue in this docket. Consistent with past practice we therefore propose to limit Schedules

38, 47, 49, and 93 to two times the overall base rate increase. We also propose to limit the subsidy to the lesser of 9.5 cents/kWh or a volumetric subsidy that ensures that the irrigation schedules do not receive a decrease in their distribution charges through which the CIO subsidy is applied. Over time, we will gradually move these schedules closer to cost of service while gradually sending the appropriate price signal.

Q. Why do you limit the major rate schedules to 1.25 times the average change in this docket?

A. We do so because of the significant changes in marginal cost estimation and ratespread we propose in this case. We furthermore wish to limit all of our major rate schedules increase to single digits in percent terms. However, should the base rate increase fall below 6%, we favor increasing the CIO limit to a range of 1.33 to 1.5 times the average increase for the major rate schedules.

Q. Which schedules bear the costs of mitigation of the schedules mentioned above?

A. We propose that Schedules 85 and 89 bear the majority of the mitigation burden because their increase is significantly below the average increase, even after paying for the mitigation. Schedules 15, 91, and 92 also contribute to the rate mitigation for the same reason.

Q. How do you implement the CIO mitigation?

A. We increase the System Usage Charges for Schedules 85 and 89, and the distribution charges for Schedules 15, 91, and 92 to offset the effect of the price mitigation efforts described above. Schedules receiving the CIO subsidy do so through their distribution charges. We also use the CIO to equalize the distribution charges for the outdoor lighting schedules 15 and 91. PGE Exhibit 1503 shows the development of this offset.

IV. Other Rate Schedule Changes

Q. Please describe Schedule 145, the Boardman Power Plant Operating Life Adjustment.

A. Schedule 145 is proposed as an automatic adjustment clause that implements the revenue requirement changes resulting from a Commission-authorized change in the Boardman Coal Plant's currently assumed end-of-life. The schedule proposes that revenue requirement changes be spread on an equal percent of Energy Charge revenues, exempting Schedules 76R, 485, and 489. PGE Exhibit 1501 explains the intent and general function of Schedule 145. The rate is initially set at zero and will be adjusted as necessary consistent with the provisions of the schedule.

Q. Please describe Schedule 141, the Pension Adjustment Mechanism.

A. Schedule 141 is also proposed as an automatic adjustment clause. It tracks the differences in pension expense and financing costs on incremental cash contributions relating to the employee pension program. We propose that these differences be spread on an equal percent of revenues basis. PGE Exhibit 1501 further explains the operation of this supplemental adjustment schedule. The rates for 2011 are set to zero.

Q. Do you propose to continue Schedule 123, the Sales Normalization Adjustment?

A. Yes. We propose to make Schedule 123 an ongoing decoupling mechanism that continues to align customer and PGE interests in pursuing energy efficiency. The current Schedule 123 was implemented just over one year ago with an initial two year term. In order for PGE to continue the mechanism, PGE must request an extension either by separate filing, or as part of a general rate filing. With this filing we are requesting the extension of Schedule 123.

PGE Exhibit 1507 contains an assessment of the mechanism that responds to the six questions the Commission posed in Order No. 09-020. The assessment shows that the decoupling pilot has functioned consistent with the intent of the mechanism. Notwithstanding our limited experience to date, decoupling is expected to provide benefits to both customers and PGE. These benefits include aligning customer and PGE interests to remove contradictory regulatory incentives towards increased energy efficiency.

Q. Please describe the limited changes you propose to Schedule 123, the Sales Normalization Adjustment.

A. First, we propose to update the SNA reference prices consistent with changes in unit fixed and variable charges for both Schedules 7 and 32.

Second, we propose to similarly update the Lost Revenue Recovery Adjustment for the other applicable schedules.

Third, we propose to remove the provision in Special Condition 3 that allows balances in excess of the 2% rate impact to be carried over from one year to the next. This change effectively creates an annual "hard cap" on amounts that can be recovered and is consistent with OPUC Order No. 09-176.

Finally, we propose to remove Special Condition 4 in order to allow Schedule 123 to continue beyond the pilot termination date of January 31, 2011.

Q. Do you propose to make this schedule conform to an annual period rather than the current February through January period?

A. Yes. We propose that for 2011 only, the SNA portion (Schedules 7 and 32) of Schedule 123 be calculated on an eleven month basis presuming that January sales per customer are at forecast levels. This allows for an eventual transition to a calendar basis beginning in 2012 and it allows for January 2011 to be incorporated into the February 2010 to January 2011 period consistent with Order No. 09-020.

Q. Do you propose other procedural changes to Schedule 123?

A. No. The Schedule 123 Sales Normalization Adjustment process requires that PGE file by April 1, the proposed Schedule 123 prices, effective June 1. For the first year, we expect a refund for Schedule 7 and a surcharge for Schedule 32.

Q. What changes do you propose to Schedule 126?

A. We propose to change the Earnings Test section to remove the earnings deadbands. We also propose to change the Negative Annual Power Cost Deadband and the Positive Annual Power Cost Deadband sections consistent with the testimony contained in PGE Exhibit 200.

Q. Why are you proposing to change the Schedule 300 prices?

A. We propose to change the Service of Limited Duration prices in order that they reflect more current cost estimates. The current prices recover only approximately 55% to 76% of the estimated costs of providing these services. The detailed calculations for the proposed prices are contained in the Pricing work papers.

Q. Have the appropriate test-period revenue and expense accounts been adjusted to reflect the proposed Schedule 300 price changes?

A. Not yet. The appropriate level of expense and revenue associated with these activities will have to be adjusted when PGE next updates its 2011 test period revenue requirements.

V. Qualifications

Q. Mr. Kuns, please state your educational background and qualifications.

A. I graduated from Linfield College in 1973 with a Bachelor of Arts in Economics. I received a Master in Business Administration degree from Claremont Graduate School.

In 1979, I joined PGE in the Rates and Regulatory Affairs Department and have held various positions in the regulatory, marketing, and planning areas. My current position is Manager of Pricing and Tariffs.

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

PORTLAND GENERAL ELECTRIC COMPANY
TABLE OF CONTENTS
RATE SCHEDULES

PORTLAND GENERAL ELECTRIC COMPANY
TABLE OF CONTENTS
RATE SCHEDULES

PORTLAND GENERAL ELECTRIC COMPANY
TABLE OF CONTENTS
RATE SCHEDULES

TABLE OF CONTENTS
RATE SCHEDULES (Concluded)

SCHEDULE 7
RESIDENTIAL SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Residential Customers.

MONTHLY RATE

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

Basic Charge			
Single Phase Service	$10.00		
Three Phase Service	$14.00		**(I)**
Transmission and Related Services Charge	0.243	¢ per kWh	**(I)**
Distribution Charge	3.349	¢ per kWh	**(I)**
Energy Charge			
Standard Service			
First 500 kWh	5.900	¢ per kWh	**(I)(C)**
501 – 1,000 kWh	7.643	¢ per kWh	**(I)(C)**
Over 1,000 kWh	8.400	¢ per kWh	**(I)(C)**
Time-of-Use (TOU) Portfolio Option (enrollment is necessary)			
On-Peak Period	13.527	¢ per kWh	**(I)**
Mid-Peak Period	7.643	¢ per kWh	**(I)**
Off-Peak Period	4.509	¢ per kWh	**(I)**
First 500 kWh block adjustment	(1.743)	¢ per kWh	**(I)(C)**
Over 1,000 kWh block adjustment	0.757	¢ per kWh	**(I)(C)**
			(D)

* See Schedule 100 for applicable adjustments.

SCHEDULE 7 (Concluded)

SPECIAL CONDITIONS (Continued)
Pertaining to the TOU Option (Continued) **(D)**

4. The Customer must provide the Company access to the meter on a monthly basis. **(T)**

5. After a Customer's initial 12 months of service on the TOU Option, the Company will calculate what the Customer would have paid under Standard Service and compare billings. If the Customer's Energy Charge billings (including all applicable supplemental adjustments) under the TOU Option exceeded Standard Service Energy Charge (including all applicable supplemental adjustments) by more than 10%, the Company will issue the Customer a refund for the amount in excess of 10% either as a bill credit or refund check. No refund will be issued for Customers not meeting the 12 month requirement. **(T)** **(C)**

6. The Company may recover lost revenue from the TOU Option through Schedule 105. **(T)**

7. Billing will begin for any Customer on the next regularly scheduled meter reading date following the initialization meter reading made on a regularly scheduled meter reading date. **(T)**

8. The Company may choose to offer promotional incentives, including but not limited to rebates or coupons. **(T)**

SCHEDULE 9
STABLE RATE PILOT
(NO NEW SERVICE)

PURPOSE

This pilot is a renewable Portfolio option which provides price stability and promotes the development of new renewable energy resources.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To the first 5 aMW (43,800,000 kWh) of total estimated annual load from Residential and Small Nonresidential Customers. This schedule is available only to those customers enrolled under Schedule 9 as of May 31, 2007.

MONTHLY RATE

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

Basic Charge:

Residential Basic Charge:		
Single Phase	$10.00[(1)]	**(I)**
Three Phase	$14.00[(1)]	
Nonresidential Basic Charge		
Single Phase	$12.00[(1)]	
Three Phase	$16.00[(1)]	

Stable Rate:

Residential Stable Rate	8.780 ¢ per kWh[(2)]
Nonresidential Stable Rate	9.740 ¢ per kWh[(2)]
Wind Development Fund	0.300 ¢ per kWh[(2)]

(1) The Basic Charge for Residential and Nonresidential Customers under this schedule will mirror the Basic Charge in Schedule 7 and Schedule 32. The Basic Charge may fluctuate with changes in the respective schedules.
(2) The Residential Stable Rate, the Nonresidential Stable Rate and Wind Development Fund (WDF) Charge will not be modified for the term of this pilot.

SCHEDULE 12
RESIDENTIAL CRITICAL PEAK PRICING PILOT

PURPOSE

This Critical Peak Pricing (CPP) pilot is a demand response option for eligible residential Customers. CPP provides Customers a price incentive to curtail peak loads during Critical Peak hours up to ten days for each six month season. The Company will notify the Customer on the day prior to each Load Reduction Day. The CPP pilot is expected to be conducted from November 1, 2010 through October 31, 2012.

AVAILABLE

In all territory served by the Company.

APPLICABLE

Subject to selection by the Company, approximately 2,000 eligible Residential (Schedule 7) Customers may elect to participate in the CPP pilot. Eligible Customers must have an Advanced Metering Infrastructure (AMI) meter. Participating Customers will be transferred from Schedule 7 to Schedule 12 for the season(s) of participation in the CPP pilot.

MONTHLY RATE

For purposes of this schedule, there are two seasons, Summer (May 1 – October 31) and Winter (November 1 – April 30). For each season a Customer participates in the CPP pilot, the Customer will be billed pursuant to this Schedule 12. For Customers who participate in the CPP pilot for only one season, Schedule 12 will apply for the season the Customer participates in the CPP pilot, and Schedule 7 will apply for the season the Customer does not participate in the CPP pilot.

Subject to approved rate revisions prior to CPP pilot implementation, the sum of the following charges per Point of Delivery (POD)* will apply to Customers participating in the CPP pilot:

Basic Charge			
Single Phase Service	$10.00		
Three Phase Service	$14.00		(I)
Transmission and Related Services Charge	0.243	¢ per kWh	
Distribution Charge	3.349	¢ per kWh	
Energy Charge			
Off-Peak Period	6.100	¢ per kWh	
On-Peak Period	7.600	¢ per kWh	
Critical Peak (when called)	35.930	¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.

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	0.195	¢ per kWh	**(I)**
Distribution Charge	3.654	¢ per kWh	**(I)**
Cost of Service Energy Charge	5.540	¢ 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	$11.89 [2]	(I)
	400	21,000	147	19.56 [2]	
	1,000	55,000	374	41.71 [2]	
HPS	70	6,300	30	8.28 [2]	
	100	9,500	43	9.55	
	150	16,000	62	11.36	
	200	22,000	79	13.41	
	250	29,000	102	15.60	
	310	37,000	124	18.41 [2]	
	400	50,000	163	21.37	
Flood, HPS	100	9,500	43	9.94 [2]	
	200	22,000	79	13.50 [2]	
	250	29,000	102	15.95	
	400	50,000	163	21.69	
Shoebox, HPS (bronze color, flat	70	6,300	30	9.09	
lens or drop lens, multi-volt)	100	9,500	43	10.52	
	150	16,500	62	12.58	
Special Acorn Type, HPS	100	9,500	43	13.42	
HADCO Victorian, HPS	150	16,500	62	14.91	
	200	22,000	79	16.64	
	250	29,000	102	18.89	
Early American Post-Top, HPS					
Black	100	9,500	43	10.51	
Special Types					
Cobrahead, Metal Halide	175	12,000	71	12.47	
Flood, Metal Halide	400	40,000	156	21.02	
Flood, HPS	750	105,000	285	35.60	(I)

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

SCHEDULE 15 (Continued)

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

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate Per Luminaire[1]	
Special Types (Continued)					
HADCO Independence, HPS	100	9,500	43	$12.77	(I)
	150	16,000	62	14.56	(I)
HADCO Capitol Acorn, HPS	100	9,500	43	17.09	(R)
	150	16,000	62	18.88	(R)
	200	22,000	79	20.48	(I)
	250	29,000	102	22.64	
HADCO Techtra, HPS	100	9,500	43	20.44	
	150	16,000	62	22.23	
	250	29,000	102	32.63	
KIM Archetype, HPS	250	29,000	102	20.23	
	400	50,000	163	25.76	
Holophane Mongoose, HPS	150	16,000	62	13.59	
	250	29,000	102	17.44	
	400	50,000	163	23.20	(I)

Rates for Area Light Poles

Type of Pole	Pole Length (feet)	Monthly Rate Per Pole
Wood, Standard	35 or less	$5.98
	55 or less	7.51
Wood, Painted for Underground	35 or less	6.99 [2]
Wood, Curved Laminated	30 or less	8.68 [2]
Aluminum, Regular	16	7.40
	25	12.03
	30	13.03
	35	14.33
Aluminum, Fluted Ornamental	14	14.07

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

SCHEDULE 32
SMALL NONRESIDENTIAL
STANDARD SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

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

MONTHLY RATE

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

Basic Charge			
Single Phase Service	$12.00		
Three Phase Service	$16.00		
Transmission and Related Services Charge	0.228	¢ per kWh	(I)
Distribution Charge			
First 5,000 kWh	3.541	¢ per kWh	
Over 5,000 kWh	0.817	¢ per kWh	
Energy Charge			
Standard Service	6.487	¢ per kWh	
or			
Time-of-Use (TOU) Portfolio Option (enrollment is necessary)			
On-Peak Period	11.135	¢ per kWh	
Mid-Peak Period	6.487	¢ per kWh	
Off-Peak Period	3.709	¢ per kWh	(I)
			(D)

* 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. **(C)**

The Daily Price will consist of:

- the Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Firm Index)
- plus 0.258¢ per kWh for wheeling **(I)**
- times a loss adjustment factor of 1.0826 **(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.

ADJUSTMENTS

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

SPECIAL CONDITIONS

1. Customers served under this schedule may at any time notify the Company of their intent to choose Direct Access Service. Notification must conform to the requirements established in Rule K.

2. Customers must enroll to receive service under any portfolio option. Customers may initially enroll or make one portfolio change per year without incurring the Portfolio Enrollment Charge as specified in Schedule 300.

SCHEDULE 32 (Continued)

SPECIAL CONDITIONS (Continued)

Pertaining to Renewable Portfolio Options

1. Service will become effective with the next regularly scheduled meter reading date provided the Customer has selected the option at least five days prior to their next scheduled meter read date. Absent the five-day notice, the change will become effective on the subsequent meter read date. Service may be terminated at the next regularly scheduled meter reading provided the Company has received notice two weeks prior to the meter read date. Absent the two-week notice, the termination will occur with the next subsequent meter reading date.

2. The Company will not accept enrollments from accounts with poor credit history. For the purposes of this rate schedule, poor credit history is defined as: a) having a time payment agreement that has not been kept current from month to month, b) having received two or more final disconnect notices in the past 12 months; or c) having been involuntarily disconnected in the past 12 months.

3. The Company will use reasonable efforts to acquire renewable energy, but does not guarantee the availability of renewable energy sources to serve Renewable Portfolio Options. The Company makes no representations as to the impact on the development of renewable resources or habitat restoration projects of Customer participation.

Pertaining to the TOU Option

1. Service may be terminated at the next regularly scheduled meter reading provided the Company has received notice two weeks prior to the meter read date. Absent the two-week notice, the termination will occur with the next subsequent meter reading date.

2. Participation requires a one year commitment by the Customer. Generally, if a Customer requests removal from the TOU Option, the Customer will be required to wait 12 months before re-enrolling. However, a Customer may request to reinstate service within 90 days of termination, in which case the Portfolio Enrollment Charge will be waived.

3. The Customer must take service at 120/240 volts or greater. Single phase 2-wire grounded service is not eligible because of special metering requirements.

4. The Customer must provide the Company access to the meter on a monthly basis. **(T)(D)**

SCHEDULE 32 (Concluded)

SPECIAL CONDITIONS (Continued)

Pertaining to the TOU Option (Continued)

5. At the end of the Customer's first 12 months of service under the TOU Option, the Company will calculate what the Customer would have paid under Standard Service and compare billings. If the Customer's Energy Charge billings (including all applicable supplemental adjustments) under the TOU Option exceeded the Standard Service Energy Charge (including all applicable supplemental adjustments) by more than 10%, the Company will issue the Customer a refund for the amount in excess of 10% either as a bill credit or refund check. No refund will be issued for Customers not meeting the 12-month requirement. **(T)** **(C)**

6. The Company will recover lost revenue from the TOU Option through Schedule 105. **(T)**

7. Billing will begin for any Customer on the next regularly scheduled meter reading date following the initialization meter reading made on a regularly scheduled meter reading date. **(T)**

8. The Company may choose to offer promotional incentives, including but not limited to rebates or coupons. **(T)**

TERM

Service under this schedule will not be for less than one year.

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

AVAILABLE

In all territory served by the Company.

APPLICABLE

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

MONTHLY RATE

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

Basic Charge			
Single Phase Service	$20.00		
Three Phase Service	$25.00		
Transmission and Related Services Charge	0.216	¢ per kWh	**(I)**
Distribution Charge	5.372	¢ per kWh	**(I)**
Energy Charge**			
On-Peak Period	6.756	¢ per kWh	**(R)**
Off-Peak Period	5.506	¢ 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 (Concluded)

DIRECT ACCESS DEFAULT SERVICE

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

Daily Price Option - The Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Firm Index) plus 0.258¢ 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 Quarterly Election Enrollment Window. **(I)**

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

Secondary Delivery Voltage 1.0826 **(R)**

ADJUSTMENTS

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

SPECIAL CONDITIONS

1. Service under this schedule will begin on the first day of the Customer’s regularly scheduled Billing Period.

2. In no case will the Company refund a Customer by retroactively adjusting the rate at which service was billed prior to the date the Customer begins service on this schedule.

(D)

TERM

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

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.

MONTHLY RATE

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

Basic Charge			
Summer Months**	$25.00		
Winter Months**	No Charge		
Transmission and Related Services Charge	0.260	¢ per kWh	(I)
Distribution Charge			
First 50 kWh per kW of Demand	5.219	¢ per kWh	
Over 50 kWh per kW of Demand	3.219	¢ per kWh	
Energy Charge***	7.335	¢ 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.

MONTHLY RATE

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

Basic Charge			
Summer Months**	$30.00		
Winter Months**	No Charge		
Transmission and Related Services Charge	0.254	¢ per kWh	(I)
Distribution Charge			
First 50 kWh per kW of Demand	3.276	¢ per kWh	
Over 50 kWh per kW of Demand	1.276	¢ per kWh	
Energy Charge***	7.227	¢ 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	$1,310.00	$1,040.00	$2,020.00	**(I)**
Transmission and Related Services Charge				
per kW of monthly On-Peak Demand	$0.88	$0.85	$0.84	**(I)**
Distribution Charges				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.77	$1.73	$1.73	**(R)(I)(C)**
Over 4,000 kW	$0.38	$0.34	$0.34	**(R)(C)**
per kW of monthly On-Peak Demand	$2.05	$1.98	$0.91	**(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	0.427 ¢	0.403 ¢	0.389 ¢	**(I)**
Energy Charge				
per kWh	See Energy Charge Below			

* See Schedule 100 for applicable adjustments.

SCHEDULE 75 (Continued)

ENERGY CHARGE (Continued)

Baseline Energy (Continued)

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

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

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

Scheduled Maintenance Energy

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

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

Unscheduled Energy

Any Electricity provided to the Customer that does not qualify as Baseline Energy or Scheduled Maintenance Energy will be Unscheduled Energy and priced at an Hourly Rate consisting of the Dow Jones Mid-Columbia Hourly Firm Electricity Price Index (DJ-Mid-C Hourly Firm Index) plus 0.258 ¢ per kWh for wheeling, a 0.300¢ per kWh recovery factor, **(I)**
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	1.0337	
Primary Delivery Voltage	1.0484	**(R)**
Secondary Delivery Voltage	1.0826	**(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	(C)
Transmission and Related Services Charge per kW of Daily Economic Replacement Power (ERP) On-Peak Demand per day	$0.034	$0.033	$0.033	(I)
Daily ERP Demand Charge per kW of Daily ERP Demand during On-Peak hours per day**	$0.080	$0.077	$0.035	(I)(R)
System Usage Charge per kWh of ERP	0.427 ¢	0.403 ¢	0.389 ¢	(I)
Transaction Fee per Energy Needs Forecast (ENF)	$50.00	$50.00	$50.00	(C)
Energy Charge* per kWh of ERP	See below for ERP Pricing			

* See Schedule 100 for applicable adjustments.

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

SCHEDULE 76R (Continued)

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

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

ERP Pricing

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

Short-Notice ERP: The Short Notice ERP Energy Charge will be an Hourly Rate consisting of the Dow Jones Mid-Columbia Hourly Price Index (DJ-Mid-C Hourly Index) plus a 5% adder, which will not be less than 0.15¢ per kWh, plus 0.258¢ 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 0.258¢ 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 0.258¢ per kWh for wheeling, plus losses. At customer request and based on the submitted Monthly ENF, the Company will provide a price quote for the next full calendar month for the ENF commodity energy only amount specified by the customer at the time of the request. The Company will respond to the request with a quote within 4 hours or as otherwise mutually agreed to. Customer will accept or reject the quote within 30 minutes. Customer communication regarding a price quote will be in the manner agreed to by the Company and the Customer. The quote may incorporate reasonable premiums to reflect the additional cost of ENF amounts that are in nonstandard block sizes (i.e., other than multiples of 25 MW) and such premium will not be separately stated. **(I)**

SCHEDULE 76R (Continued)

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

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

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

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

Subtransmission Delivery Voltage	1.0337	
Primary Delivery Voltage	1.0484	**(R)**
Secondary Delivery Voltage	1.0826	**(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 Dow Jones Mid-Columbia Hourly Price Index (DJ-Mid-C Hourly Index), plus 0.258¢ per kWh for wheeling, plus losses. **(I)**
- For negative Imbalance Energy (where Customer receives less ERP than the ENF), the Imbalance Energy is multiplied by the Settlement Price of the DJ-Mid-C Hourly Index plus 0.258¢ per kWh for wheeling, plus losses. **(I)**

SCHEDULE 76R (Continued)

IMBALANCE ENERGY SETTLEMENT (Continued)

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

- For positive excess Imbalance Energy, the excess Imbalance Energy multiplied by the Settlement Price, which is the Dow Jones Mid-Columbia Hourly Price Index (DJ-Mid-C Hourly Index), plus 10%, plus 0.258¢ per kWh for wheeling, plus losses. **(I)**
- For negative excess Imbalance Energy, the excess Energy Imbalance is multiplied by the Settlement Price of the DJ-Mid-C Hourly Index, less 10%, plus 0.258¢ 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 77 (Continued)

PAYMENTS (Continued)

For the year of 2011, the reference fuel costs per MWh for an SCCT are: **(C)**

Jan 2011	Feb 2011	Jul 2011	Aug 2011	Sep 2011	Dec 2011
$64.28	$64.01	$54.20	$54.75	$55.03	$63.46

(C)
(I)

The Energy Reduction Payment rates will be updated annually by December 1st. Evaluation and settlement of the Energy Reduction Payment will occur within 60 days of the Firm Load Curtailment Event.

FIRM LOAD REDUCTION OPTION AND ELECTION

The Firm Load Reduction Options and terms are:

Firm Demand Reduction Options	Advance Notification Hours	Event Duration Consecutive Hours per Day
A	2	4
B	4	4

The Customer must select at the time of enrollment the applicable Firm Load Reduction Option to be in effect for the duration of the contract term.

FIRM LOAD REDUCTION

Firm Load Reduction will be measured as a reduction of Demand as specified in the Firm Load Reduction Agreement from a predetermined Daily Baseline Demand Profile during each hour of the Load Curtailment Event.

Daily Baseline Demand Profile

Daily Baseline Demand Profile is defined by measuring the participating Customer's Demand for each 15-minute interval over a minimum of the most recent 14 typical operational days prior to the Load Curtailment Event and combined into an average hourly Demand profile on an hour-by-hour basis.

Typical operational days exclude days that a Customer has participated in a Curtailment Event. If the Customer's energy usage is highly variable, the Company may, in collaboration with the Customer, develop at time of enrollment, an alternate method to determine baseline usage.

FIRM ENERGY REDUCTION

The Firm Energy Reduction Amount is the difference between the Customer's Baseline Energy Usage and the Customer's measured hourly energy usage during the Load Curtailment Event.

SCHEDULE 77 (Continued)

ENROLLMENT

The enrollment period for qualified Customers occurs annually from October 1st to October 15th (or the following business day if the 1st or the 15th falls on a weekend or holiday). Within five days of enrollment, the Company will confirm receipt of the PODID(s) the Customer intends to enroll under this schedule and will send a written contract to the Customer's representative. No later than October 30th (or the next business day if the 30th falls on a weekend or holiday), the Customer must sign a written Firm Load Reduction Agreement (FLRA) with the Company. The enrollment will be effective for the calendar year beginning January 1st, following the enrollment window. The Customer shall re-enroll annually in order to remain on this schedule.

SPECIAL CONDITIONS

1. Customers participating on the Company's Schedule 200 program may not use their on-site generation equipment for load reductions to meet load reduction commitments under this tariff. Customer on-site generation not under Schedule 200 must be permitted through applicable local, State and Federal agencies prior to its use to meet reduction commitments under this tariff.

2. Customers participating in Schedules 84, 86, 485, 489, 575, 583, 585 and 589 are not eligible. **(C)**

3. Firm Load Reduction by Schedule 75 Customers will not exceed the Customer's Baseline Demand as specified in the written service agreement between the Customer and the Company. Customer cannot use purchases under Schedule 76 to meet load reduction commitments under this tariff.

4. The Company is not responsible for any consequences to the participating Customer that results from the Firm Load Curtailment Event or the Customer's effort to reduce Energy in response to a Firm Load Curtailment Event. The Customer may not participate in this rider until the Company has installed metering that records usage in 15 minute intervals. The Customer will provide communication service to the meter if requested by the Company.

5. This tariff is not applicable when the Company requests or initiates load curtailment affecting a Customer PODID under system emergency conditions.

6. The Company will not cancel or shorten the duration of a Firm Curtailment Event once notification has been given without the consent of the Customer.

7. Monthly Reservation Payments and Energy Reduction Payments made to individual Customers under this tariff will be recovered from all Customers through the Company's Schedule 125 and Schedule 126 for the corresponding enrollment year.

8. The Company will file any adjustment to the Monthly Reservation Rate not less than two months prior to the annual enrollment period.

SCHEDULE 81
NONRESIDENTIAL
EMERGENCY DEFAULT SERVICE

AVAILABLE

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

APPLICABLE

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

MONTHLY RATE

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

ENERGY CHARGE DAILY RATE

The Energy Charge Daily Rate will be 125% of the Dow Jones Mid-Columbia Daily on- and off-peak Firm Electricity Price Index (DJ-Mid-C Firm Index) plus 0.258¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on-peak and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported. **(I)**

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

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

Subtransmission Delivery Voltage	1.0337	
Primary Delivery Voltage	1.0484	**(R)**
Secondary Delivery Voltage	1.0826	**(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) **(C)**

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customers whose Demand has not exceeded 200 kW more than once in the preceding 13 months, or with seven months or less of service has not had a Demand exceeding 200 kW. **(C)** **(C)**

MONTHLY RATE

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

Basic Charge			(D)
Single Phase Service	$20.00		
Three Phase Service	$30.00	(I)	
Transmission and Related Services Charge			
per kW of monthly Demand	$0.88		
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 30 kW	$3.00		
Over 30 kW	$2.50	(I)	
per kW of monthly Demand	$1.83	(R)	
Energy Charge			
Cost of Service Option per kWh	6.413 ¢	(I)	
See below for Daily Pricing Option description.			(C)
System Usage Charge			
per kWh	0.380 ¢	(I)	(D)

* 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.

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 **(T)**

Daily Price Option - The Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Firm Index) plus 0.258¢ per kWh for wheeling, plus losses. If prices **(I)** are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported. To begin service under this option, the Customer receiving service under Cost of Service price option will notify the Company by the close of the November Election Window or for eligible Customers, the close of a Quarterly Election Enrollment Window.

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

		(D)
Secondary Delivery Voltage	1.0826	**(R)**
		(D)

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

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 83 (Continued)

ELECTION WINDOW

Quarterly Election Window

The Quarterly Election Window begins at 8:00 a.m. on February 15th, May 15th and August 15th (or the following business day if the 15th falls on a weekend or holiday). The Quarterly Election Windows 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.

During the Quarterly 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; for the May 15th election window, the election is effective July 1st and for the August 15th election window, the election is effective on October 1st. A Customer may not choose to move from an alternative option back to Cost of service during a Quarterly Election Window.

November Election Window

Enrollment for 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 Enrollment Windows 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.

During an Election Window, Customers may notify the Company of a choice to change service options using the Company's website, PortlandGeneral.com/business

MINIMUM CHARGE

The Minimum Charge will be the Basic, Distribution and Transmission 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 service facilities. **(C)**

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 84
LARGE NONRESIDENTIAL
LARGE LOAD SPLIT SERVICE RIDER OPTION

PURPOSE

The Large Load Split Service Rider Option allows a Customer to receive Direct Access Service for a percentage of its usage, while the remainder is served on the Cost of Service option.

APPLICABILITY

To Large Nonresidential Customers served on Schedule 85 or Schedule 89 that demonstrate the following: **(C)**

1) Usage in the most recent 12 months or, projected annual usage or where 12 months of usage history is not available, of at least 87,600,000 kWh (10 MWa) from one or more participating Points of Delivery (PODs);
2) An election to maintain at least 10 MWa usage on this option;
3) A Facility Capacity of at least 250 kW at each participating POD; and
4) An average non-coincident monthly load factor for the aggregated PODs participating of at least 60%, determined by the Company based on the historical usage information.

DESCRIPTION OF SERVICE OPTION

A Customer receiving service under this rider must elect 10% to 50% of eligible load to be served on Direct Access Service. All remaining load will be served by the Company.

DIRECT ACCESS BLOCK

The Direct Access Block is a fixed kWh served on Direct Access Service.

The Customer will choose the percentage of load to be served on Direct Access Service. The Company will determine the Direct Access Block by multiplying that percentage by the Customer's annual historical kWh usage for all participating PODs with the result divided by 8,760 hours, subject to the following limits:

- A Direct Access Block will not result in more than 50% of the annual historical usage.
- A POD may not have more than five consecutive days (or 120 hours) where the Direct Access Block is greater than the historical usage. When this occurs, the percentage that determines the Direct Access Block will be reduced for all of the Customer's PODs.

The Direct Access Block will remain unchanged for the calendar year [which may be less than 12 months if an Electricity Service Supplier (ESS) does not make a timely submittal of the required Direct Access Service Requests (DASRs)].

SCHEDULE 84 (Continued)

COMPANY SERVED LOAD

The Company Served Load is the difference between the Direct Access Block and the metered interval load data for each POD by hour. If actual usage in an hour is less than the Direct Access Block, the Company supplied Energy is deemed to be zero for the hour.

DIRECT ACCESS SERVICE

The Customer must arrange for an ESS to provide Direct Access Service for the Direct Access Block. The ESS is responsible for enrolling each participating POD in Direct Access Service and meeting all requirements defined in Rule G for timely DASR submittals. Beginning on January 1st, all participating PODs will be billed at the Daily Price until Direct Access Service commences for the participating PODs.

MONTHLY RATE

The Monthly Rate is the sum of the following charges:

Energy Charge

For the Company Served Load, the Cost of Service Monthly Energy Charge for the appropriate Delivery Voltage under Schedule 85 or Schedule 89 as applicable will apply. **(C)**

The Customer's ESS will bill separately for Energy provided for the Direct Access Block.

Other Charges

The following charges will be applied to the Customer's total usage for each POD: The Basic Charge, Transmission and Related Services Charge, Distribution Charge, System Usage Charge, Reactive and other applicable charges except the Energy Charge and including supplemental adjustments applied to each POD's total Energy, Demand, Facility Capacity and Reactive Demand.

A credit will be applied to the Direct Access Block billing for Transmission and Related Services. The credit will be equal to the Schedules 85 or 89 Transmission and Related Services Charge applied to the Direct Access Block Demand. **(C)**

SCHEDULE 84 (Concluded)

ENROLLMENT

The Company will provide a list of eligible PODs to Customers by September 15th of each calendar year (or the following business day if the 15th falls on a weekend or holiday).

By 5:00 p.m. on the last business day of September, the Customer must provide written notification to the Company verifying the following:

1) The Customer's intent to elect the service under this Rider.
2) A list of the PODs the Customer intends to enroll under this service option during the November Election Window (as defined in Schedules 85 and 89). **(C)**
3) The proposed percentage of load to be served on Direct Access Service. This designation will be used by the Company to determine the Direct Access Block.

By October 15th (or the following business day if the 15th falls on a weekend or holiday), the Company will confirm receipt of the election and the PODs the Customer intends to enroll. In order to receive service under this rider, the Customer must confirm enrollment during the November Election Window. After the Customer selection is confirmed during the November Election Window, the Company will provide the Customer with POD identification (PODID) numbers to be used by an ESS to enroll the Direct Access Block PODs in Direct Access. The Customer is responsible for furnishing this information to its selected ESS.

SET UP FEE

Customers notifying the Company of their intent to receive service under this rider will be charged a one-time non-refundable fee of $70 per each designated POD. This fee will be due with the Customer's written notification in September for a service election in November and service the following January.

TERM

All of the Customer's enrolled PODs will remain on this option for the entire calendar year and must be reenrolled annually.

SCHEDULE 85
LARGE NONRESIDENTIAL
STANDARD SERVICE
(201 – 1,000 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customers whose Demand has exceeded 200 kW but not exceeded 1,000 kW more than once in the preceding 13 months, or with seven months or less of service has exceeded 200 kW but not had a Demand exceeding 1,000 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	$400.00	$360.00
Transmission and Related Services Charge		
per kW of monthly On-Peak Demand	$0.88	$0.85
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 200 kW	$2.04	$1.97
Over 200 kW	$2.04	$1.97
per kW of monthly On-Peak Demand	$1.95	$1.88
Energy Charge		
On-Peak Period***	6.539 ¢	6.347 ¢
Off-Peak Period***	5.360 ¢	5.168 ¢
See below for Daily Pricing Option description.		
System Usage Charge		
per kWh	0.400 ¢	0.386 ¢

* 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.

NON COST OF SERVICE OPTION

Daily Price Option - The Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Firm Index) plus 0.258¢ 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 Quarterly Election Enrollment Window.

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

Primary Delivery Voltage	1.0484
Secondary Delivery Voltage	1.0826

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 85 (Continued)

ELECTION WINDOW

Quarterly Election Window

The Quarterly Election Window begins at 8:00 a.m. on February 15th, May 15th and August 15th (or the following business day if the 15th falls on a weekend or holiday). The Quarterly Election Windows 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.

During the Quarterly 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; for the May 15th election window, the election is effective July 1st and for the August 15th election window, the election is effective on October 1st. A Customer may not choose to move from an alternative option back to Cost of service during a Quarterly Election Window.

November Election Window

Enrollment for 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 Enrollment Windows 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.

During an Election Window, Customers may notify the Company of a choice to change service options using the Company's website, PortlandGeneral.com/business

MINIMUM CHARGE

The Minimum Charge will be the Basic, Distribution and Transmission 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 service facilities. The minimum Facility Capacity and Demand (in kW) will be 200 kW for primary voltage service.

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 85 (Concluded)

ADJUSTMENTS

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

TERM

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

SCHEDULE 86
DEMAND BUY BACK RIDER
NONRESIDENTIAL

PURPOSE

This rider is an optional, supplemental service that allows participating Customers an opportunity to voluntarily reduce their Electricity usage in return for a payment, at times and prices determined by the Company.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To qualifying Industrial, Commercial and General Service electric Customers served under Schedules 38, 83, 85, 89 and 99 who satisfy the conditions contained in this rider. Customers **(C)** must execute a Demand Buy Back Agreement prior to receiving service and have the capability to reduce not less than 250 kW aggregated from one or more points of delivery for each hour during a Buy Back Event.

BUY BACK CREDIT DETERMINATION

Energy Price

The Energy Price will be a price or prices quoted by the Company for a specified Buy Back Event, subject to requirements and other conditions described in Special Conditions.

Hourly Credit

Buy Back Amount (kWh) **X** Energy Price **=** Hourly Credit

The Hourly Credit is the amount owed to the Customer for each hour of the Buy Back Event. The Hourly Credit is determined by multiplying the Buy Back Amount by the Energy Price. The Hourly Credit will not be less than zero.

Buy Back Credit

The Buy Back Credit is the amount paid to the Customer for its Electricity reduction during a Buy Back Event and is the sum of each Hourly Credit during such event (minus any amounts owed as a result of failure to comply during an Extended Buy Back Event).

PAYMENTS

The Company will pay the Buy Back Credit to the Customer within 60 days of the Buy Back Event.

SCHEDULE 87 (Continued)

STANDARD BILL

The Standard Bill is calculated by applying the Annual Cost of Service Option under Schedule 89 to a CBL for each month of the year, excluding the Reactive Demand Charge and Adjustments identified in Schedule 100. If prices are revised, those changes will be reflected in the Customer's Standard Bill based on the CBL for a given month. Hourly Energy prices are applied only to kWh usage changes from the CBL in each hour.

CUSTOMER BASELINE LOAD (CBL)

The CBL is the Customer's hourly load for a 12-month period at typical levels of operation. It is developed based on the Customer's specific hourly load data or monthly billing data allocated to hours based on the consumption pattern agreed to by the Customer and the Company as typical of the Customer's operation.

Agreement to a CBL is a precondition for service under this schedule. The CBL is proprietary and will not be released to any other entity without the approval of the Customer and the Company. In order that the CBL reflect the Customer's Energy and Demand as accurately as possible, the Customer may request adjustments to the CBL for the following reasons:

1. The installation of permanent energy efficiency measures either as a participant in Energy Trust of Oregon programs or other verifiable conservation or technology improvement measures.
2. The addition or removal of equipment that results in a permanent change in the Customer's expected electricity consumption.

If the Customer leaves the program, he/she may not be allowed to return for a minimum of 12 months. A new CBL will be calculated in such cases based on the most recent usage. At a minimum, the CBL will be reviewed every three years and may be adjusted.

HOURLY ENERGY PRICE

Hourly Energy Prices are determined each day for the following day using Mid-Columbia Day Ahead Prices for on- and off-peak periods shaped to hourly prices based on the reported hourly Mid-Columbia prices from preceding days. The following charges will be added to the shaped hourly prices, 0.258¢ per kWh for wheeling, plus losses and the System Usage Charge as specified in Schedule 89. If prices are not reported for a particular day or days, the Company will estimate and shape prices from its hourly Energy price projections. **(I)**

In addition to the above charges, consumption of Energy above the CBL will be billed a 0.300¢ per kWh recovery factor. For consumption of Energy below the CBL, a 0.300¢ per kWh recovery factor will be subtracted from the Hourly Energy Price.

SCHEDULE 88
LOAD REDUCTION PROGRAM

PURPOSE

The Load Reduction Program is an optional, supplemental service that allows participating Customers an opportunity to voluntarily reduce Electricity usage to a Company-determined level during an Emergency Curtailment as described in Rule C(2)(B) in exchange for partial exemption from Emergency Curtailments.

AVAILABLE

In all territory served by the Company but total pledges will not exceed 5% of Company primary voltage circuits.

APPLICABLE

To an individual or a group of Large Nonresidential Customers receiving Electricity Service under Schedules 83, 85, 89, 485, 489, 583, 585 and/or 589 from one or more Point(s) of Delivery (PODs) but from the same dedicated primary circuit and able to reduce Baseline Usage from the primary circuit by a minimum of 15%. Customers applying as a group must be represented by a Lead Customer. A group may consist of multiple PODs under one Customer name that are all located on the same primary circuit. Participation is dependent upon satisfaction of all conditions contained in this schedule. **(C)**

BASELINE USAGE

The Baseline Usage is defined as the average usage for each hour for a minimum of 14 typical operational days prior to the Emergency Curtailment. Typical operational days exclude days that a Customer has participated in either an Emergency Curtailment or a Demand Buy Back Event (Schedule 86). Holidays and weekends will be excluded when determining the Baseline Usage except when the Emergency Curtailment includes weekends or holidays. The Customer may request that specific days be excluded from the 14-day baseline calculation upon demonstrating to the Company's satisfaction that the specific days are not similar days. The Company and Customer may mutually agree to use an alternate method to determine Baseline Usage when the Customer's usage is highly variable.

LOAD REDUCTION DETERMINATION

During an Emergency Curtailment, the individual Customer or group of Customers will be required to reduce Baseline Usage to a Company-determined Maximum Circuit Load (MCL). The MCL is the Customer's or group of Customer's Baseline Usage minus the necessary load reduction of 5, 10 or 15%.

SCHEDULE 89
LARGE NONRESIDENTIAL
STANDARD SERVICE
(>1,000kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has exceeded 1,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 1,000 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	$1,310.00	$1,040.00	$2,020.00	**(I)**
Transmission and Related Services Charge				
per kW of monthly On-Peak Demand	$0.88	$0.85	$0.84	**(I)**
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.77	$1.73	$1.73	**(R)(I)(C)**
Over 4,000 kW	$0.38	$0.34	$0.34	**(R) (C)**
per kW of monthly On-Peak Demand	$2.05	$1.98	$0.91	**(I) (R)**
Energy Charge				
On-Peak Period***	6.324 ¢	6.136 ¢	6.054 ¢	**(R)**
Off-Peak Period***	5.145 ¢	4.957 ¢	4.875 ¢	**(R)**
See below for Daily Pricing Option description.				**(C)**
System Usage Charge				
Per kWh	0.427 ¢	0.403 ¢	0.389 ¢	**(I)**

* See Schedule 100 for applicable adjustments.

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

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

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 **(T)**

Daily Price Option - The Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Firm Index) plus 0.258¢ 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 Quarterly Election Enrollment Window. **(I)**

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

Subtransmission Delivery Voltage	1.0337	
Primary Delivery Voltage	1.0484	**(R)**
Secondary Delivery Voltage	1.0826	**(R)**
		(D)

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

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 luminaire based on the Monthly kWhs applicable to each installed luminaire.

Transmission and Related Services Charge	0.195 ¢ per kWh	**(I)**
Distribution Charge	3.654 ¢ per kWh	**(I)**
Energy Charge		
Cost of Service Option	5.540 ¢ per kWh	**(R)**

Daily Price Option – Available only to Customers with an average load of five MW or greater. In addition to the daily Energy price, the Customer will pay a Basic Charge of $75 per month to help offset the costs of billing this option. The daily Energy price for all kWh will be the Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Firm Index) plus 0.258¢ 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 Energy Rate 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 above applicable Daily Price by 1.0826. **(R)**

To begin service under this 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 [1] notice is received to return to the Cost of Service Option.

---

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

SCHEDULE 91 (Continued)

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Installation Labor Rate [(1)]	Straight Time	Overtime
	$117.00 per hour	$165.00 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	
Cobrahead Power Doors **	100	9,500	43	*	$2.56	(R)
	150	16,000	62	*	2.57	
	200	22,000	79	*	2.61	
	250	29,000	102	*	2.61	
	400	50,000	163	*	2.62	
Cobrahead	100	9,500	43	$5.23	2.75	
	150	16,000	62	5.25	2.76	
	200	22,000	79	5.66	2.80	
	250	29,000	102	5.69	2.79	
	400	50,000	163	5.73	2.83	
Flood	250	29,000	102	6.00	2.86	
	400	50,000	163	6.02	2.88	(R)

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

SCHEDULE 91 (Continued)

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

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
Early American Post-Top	100	9,500	43	$5.71	$2.83	**(I)**
Shoebox (bronze color, flat lens, or drop lens, multi-volt)	70	6,300	30	5.84	2.82	**(R)**
	100	9,500	43	6.11	2.90	
	150	16,000	62	6.36	2.91	**(R)**

RATES FOR STANDARD POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Monthly Rates Option B
Fiberglass, Black	20	$4.10	$0.14
Fiberglass, Bronze	30	5.47	0.18
Fiberglass, Gray	30	5.49	0.18
Wood, Standard	30 to 35	4.71	0.15
Wood, Standard	40 to 55	5.91	0.20

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	$8.74	$3.23	**(I)**
HADCO Independence, HPS	100	9,500	43	8.16	3.24	
	150	16,000	62	8.17	3.25	**(I)**
HADCO Capitol Acorn, HPS	100	9,500	43	12.05	3.34	**(R)**
	150	16,000	62	12.06	3.35	
	200	22,000	79	12.06	3.35	
	250	29,000	102	12.06	3.35	**(R)**
Special Architectural Types						
HADCO Victorian, HPS	150	16,000	62	8.48	3.23	**(I)**
	200	22,000	79	8.61	3.32	
	250	29,000	102	8.69	3.32	**(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	
HADCO Techtra, HPS	100	9,500	43	$15.13	$4.21	(I)
	150	16,000	62	15.14	4.22	
	250	29,000	102	21.61	4.82	(I)
KIM Archetype, HPS	250	29,000	102	*	3.33	(R)
	400	50,000	163	*	3.32	(R)
HADCO Westbrooke, HPS	70	6,300	30	13.00	3.40	(I)
	100	9,500	43	12.96	3.39	
	150	16,000	62	12.97	3.40	
	200	22,000	79	13.11	3.40	
	250	29,000	102	13.11	3.40	(I)
Special Types						
Cobrahead, Metal Halide	175	12,000	71	5.50	2.95	
Flood, Metal Halide	400	40,000	156	6.02	3.00	(R)
Flood, HPS	750	105,000	285	8.33	3.92	
Holophane Mongoose, HPS	150	16,000	62	7.27	3.00	
	250	29,000	102	7.36	3.01	
	400	50,000	163	7.40	3.03	(R)

* Not offered.

RATES FOR CUSTOM POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Monthly Rates Option B
Aluminum, Regular	16	$5.83	$0.20
	25	9.48	0.32
	30	10.26	0.34
	35	11.29	0.38
Aluminum Davit	25	9.79	0.33
	30	10.44	0.35
	35	11.53	0.38
	40	14.08	0.47
Aluminum Double Davit	30	12.56	0.42

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	$11.08	$0.37
Aluminum, HADCO, Non-Fluted Techtra Ornamental	18	19.81	0.65
Aluminum, HADCO, Fluted Ornamental	16	10.60	0.35
Aluminum, HADCO, Non-Fluted Ornamental Westbrooke	16	15.95	0.52
Aluminum, Painted Ornamental	35	27.35	0.90
Concrete, Ameron Post-Top	25	23.42	0.78
Fiberglass, HADCO, Fluted Ornamental Black	14	6.47	0.21
Fiberglass, Regular			
color may vary	22	3.17	0.11
color may vary	35	7.47	0.25
Fiberglass, Anchor Base, Gray	35	11.95	0.40
Fiberglass, Direct Bury with Shroud	18	6.20	0.21

SERVICE RATE FOR OBSOLETE LIGHTING

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

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
Cobrahead, Mercury Vapor	100	4,000	39	*	*	
	175	7,000	66	$5.38	$2.71	**(I)**
	250	10,000	94	6.29	2.92	**(R)**
	400	21,000	147	5.45	2.79	
	1,000	55,000	374	6.23	3.08	**(R)**
Special Box Similar to GE "Space-Glo"						
HPS	70	6,300	30	8.71	2.83	**(I)**
Mercury Vapor	175	7,000	66	8.85	2.75	**(R)**

* 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	
Special Box, Anodized Aluminum Similar to GardCo Hub						
HPS	Twin 70	6,300	60	*	*	
	70	6,300	30	*	*	
	100	9,500	43	$8.50	$3.15	(R)
	150	16,000	62	*	3.16	(R)
	250	29,000	102	*	*	
	400	50,000	163	*	*	
Metal Halide	250	20,500	99	*	3.36	(I)
	400	40,000	156	*	3.74	(R)
Cobrahead, Dual Wattage, HPS						
70/100 Watt Ballast	100	9,500	43	*	2.73	(R)
100/150 Watt Ballast	100	9,500	43	*	2.73	|
100/150 Watt Ballast	150	16,000	62	*	2.74	(R)
Special Architectural Types						
KIM SBC Shoebox, HPS	150	16,000	62	*	3.65	(I)
Special Acorn-Type, HPS	70	6,300	30	8.48	2.83	(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	*	*	
Early American Post-Top, HPS						
Black	70	6,300	30	5.09	2.73	(R)
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	5.48	2.70	(R)

* 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	
Flood, HPS	70	6,300	30	$5.69	$2.80	(R)
	100	9,500	43	5.58	2.77	
	200	22,000	79	5.98	2.84	
Cobrahead, HPS						
Non-Power Door	70	6,300	30	5.18	2.79	
Power Door	310	37,000	124	6.40	3.14	(R)
Special Types Customer-Owned & Maintained						
Ornamental, HPS	100	9,500	43	*	*	
Twin Ornamental, HPS	Twin 100	9,500	86	*	*	
Compact Flourescent	28	N/A	12	*	*	

* Not offered.

RATES FOR OBSOLETE LIGHTING POLES

Type of Pole	Poles Length (feet)	Monthly Rates Option A	Option B
Aluminum Post	30	$5.83	*
Bronze Alloy GardCo	12	*	$0.24
Concrete, Ornamental	35 or less	9.48	0.32
Steel, Painted Regular **	25	9.48	0.32
Steel, Painted Regular **	30	10.26	0.34
Steel, Unpainted 6-foot Mast Arm **	30	*	0.34
Steel, Unpainted 6-foot Davit Arm **	30	*	0.35
Steel, Unpainted 8-foot Mast Arm **	35	*	0.38
Steel, Unpainted 8-foot Davit Arm **	35	*	0.38
Wood, Laminated without Mast Arm	20	5.30	0.14
Wood, Laminated Street Light Only	20	4.10	*

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

SCHEDULE 91 (Continued)

RATES FOR OBSOLETE LIGHTING POLES (Continued)

Type of Pole	Poles Length (feet)	Monthly Rates Option A	Monthly Rates Option B
Wood, Curved Laminated	30	$6.84	$0.25
Wood, Painted Underground	35	4.71	0.20
Wood, Painted Street Light Only	35	4.71	*

* Not offered.

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	
Special Architectural Types Including Philips QL Induction Lamp Systems						
HADCO Victorian, QL	85	6,000	32	$10.59	$2.05	(R)
	165	12,000	60	12.28	2.13	
HADCO Techtra, QL	85	6,000	32	13.97	2.18	
	165	12,000	60	14.68	2.22	(R)

ELECTION WINDOW

Quarterly Election Window

The Quarterly Election Window begins at 8:00 a.m. on February 15th, May 15th and August 15th (or the following business day if the 15th falls on a weekend or holiday). The Quarterly Election Windows 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.

During the Quarterly 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; for the May 15th election window, the election is effective July 1st and for the August 15th election window, the election is effective on October 1st. A Customer may not choose to move from an alternative option back to Cost of service during a Quarterly Election Window.

SCHEDULE 91 (Concluded)

SPECIAL CONDITIONS (Continued)

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

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

5. If Customer-owned (Option B) streetlighting equipment or poles are removed or relocated at the Customer's request, the Customer is responsible for the costs associated with the change.

6. If circuits or poles are removed or relocated at the Customer's request, the Customer is responsible for all associated costs for labor and materials incurred when fulfilling this request.

7. For Option C lights: When the Company provides the circuit, the Customer will incur a circuit charge of $1.38 per luminaire per month.

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

TERM

A Customer served under the Daily Pricing option may not choose service under another rate schedule until the end of the calendar year in which the pricing choice was made. **(C)**

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	0.199	¢ per kWh	**(I)**
Distribution Charge	2.563	¢ per kWh	**(I)**
Energy Charge	5.663	¢ per kWh	**(R)**

* See Schedule 100 for applicable adjustments.

ELECTION WINDOW

Quarterly Election Window

The Quarterly Election Window begins at 8:00 a.m. on February 15th, May 15th and August 15th (or the following business day if the 15th falls on a weekend or holiday). The Quarterly Election Windows 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.

During the Quarterly 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; for the May 15th election window, the election is effective July 1st and for the August 15th election window, the election is effective on October 1st. A Customer may not choose to move from an alternative option back to Cost of service during a Quarterly Election Window.

SCHEDULE 93
RECREATIONAL FIELD LIGHTING, PRIMARY VOLTAGE
STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers for recreational field lighting and related incidental lighting.

MONTHLY RATE

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

Basic Charge	$30.00		
Transmission and Related Services Charge	0.192	¢ per kWh	**(I)**
Distribution Charge	11.829	¢ per kWh	**(I)**
Energy Charge	5.470	¢ per kWh	**(R)**

* 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.

ADJUSTMENTS

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

SPECIAL CONDITION

The Customer's electrical equipment and its installation must be approved by the Company. All service under this schedule at any one location will be supplied through one meter.

TERM

Service under this schedule will not be for less than a one year.

SCHEDULE 94
COMMUNICATION DEVICES ELECTRICITY SERVICE RIDER

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments that have communication devices with energy requirements not exceeding 25 line watts per unit, that are installed on streetlights and, or traffic signals served under Schedules 91 and, or 92.

CHARACTER OF SERVICE

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

SERVICE

Service under this schedule will be based on an estimated total monthly kWh used, as determined by the Company, for all the Customer's devices. The estimated monthly usage will be updated as needed to reflect device installations or removals. Monthly kilowatt-hour usage will be computed on the basis of manufacturer's line wattage ratings of installed devices, with no allowances for outages.

MONTHLY RATE

The sum of the following charges per Point of Delivery:*

Transmission and Related Services Charge	0.199 ¢ per kWh	(I)
Distribution Charge	2.563 ¢ per kWh	(I)
Energy Charge	5.663 ¢ per kWh	(R)

* See Schedule 100 for applicable adjustments

The monthly kWh charge for service under this rider will be the number of units times estimated monthly usage determined using the following formula:

[((No. of Units x line watts per unit) x annual operating hours) / 1000] / 12

Portland General Electric Company **Sixteenth Revision of Sheet No. 100-1**
P.U.C. Oregon No. E-18 **Canceling Fifthteenth Revision of Sheet No. 100-1**

SCHEDULE 100
SUMMARY OF APPLICABLE ADJUSTMENTS

The following summarizes the applicability of the Company's adjustment schedules. **(D)**

(N)

Schs.	102 (1)	105	106 (1)	108 (3)	109 (1)	110 (1)	111	115	121	122	123 (1)	125 (1)	126	128 (4)	129 (1)	130 (1)	133	140 (1)	**141**	142	**145**
7	x	x	x	x	x	x	x	x	x	x	x	x	x				x	x	x	x	x
9			x	x				x												x	
12	x	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	x
38	x	x	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	x
49	x	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	x(2)	x(2)	x	x(2)	x(2)	x			x	x	x	x	x
76R	x	x	x	x	x	x	x	x			x						x	x	x	x	
83	x	x	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	x	x
87	x(2)	x(2)	x	x	x	x	x	x	x(2)	x(2)	x	x	x(2)				x	x	x	x	x
89	x	x	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
93		x	x	x	x	x	x	x	x	x	x	x	x				x	x	x	x	x
94		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		x(5)		x		x	x	x	x	
489	x	x	x	x	x	x	x	x			x		x(5)		x		x	x	x	x	
515	x	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	x		x(5)	x			x	x	x	x	x
538	x	x	x	x	x	x	x	x		x	x		x(5)	x		x	x	x	x	x	x
549	x	x	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(2)	x			x	x	x	x	x
576R	x	x	x	x	x	x	x	x			x						x	x	x	x	
583	x	x	x	x	x	x	x	x		x	x		x(5)	x		x	x	x	x	x	x
585	x	x	x	x	x	x	x	x		x	x		x(5)	x		x	x	x	x	x	x
589	x	x	x	x	x	x	x	x		x	x		x(5)	x		x	x	x	x	x	x
591		x	x	x	x	x		x		x	x		x(5)	x			x	x	x	x	x
592		x	x	x	x	x		x		x	x		x(5)	x			x	x	x	x	x
594		x	x	x	x	x		x		x	x		x	x			x	x	x	x	x

(N) (C) (N) (N)

(1) Where applicable. **(T)**
(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 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 and 489). **(C)** **(C)**
(5) Not applicable to Customers where service was received for the entire calendar year that the Annual Power Cost Variance accrued. **(T)**

SCHEDULE 105
REGULATORY ADJUSTMENTS

PURPOSE

The purpose of this schedule is to reflect the effects of regulatory adjustments such as net gains from nonrecurring property transactions, and costs associated with the implementation of SB 1149, and miscellaneous nonrecurring items.

APPLICABLE

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

PART A – MISCELLANEOUS ADJUSTMENTS

Part A will be adjusted annually as necessary to recover nonrecurring Regulatory Adjustments.

PART B – LARGE NON-RESIDENTIAL LOAD TRUE-UP

Part B consists of costs associated with the Schedule 128 Large Nonresidential Load Shift True-up after the November 2008 open enrollment window.

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	0.000	0.000	0.000	¢ per kWh	(N)
12	0.000	0.000	0.000	¢ per kWh	
15	0.000	0.000	0.000	¢ per kWh	
32	0.000	0.000	0.000	¢ per kWh	
38	0.000	0.009	0.009	¢ per kWh	
47	0.000	0.000	0.000	¢ per kWh	
49	0.000	0.009	0.009	¢ per kWh	
75					
Secondary	0.000	0.009	0.009	¢ per kWh(1)	
Primary	0.000	0.009	0.009	¢ per kWh(1)	
Subtransmission	0.000	0.009	0.009	¢ per kWh(1)	

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

Portland General Electric Company **Fourth Revision of Sheet No. 105-2**
P.U.C. Oregon No. E-18 **Canceling Third Revision of Sheet No. 105-2**

SCHEDULE 105 (Continued)

ADJUSTMENT RATES (Continued)

Schedule	Part A	Part B	Adjustment Rate		
76R					
Secondary	0.000	0.009	0.009	¢ per kWh	
Primary	0.000	0.009	0.009	¢ per kWh	
Subtransmission	0.000	0.009	0.009	¢ per kWh	
83	0.000	0.009	0.009	¢ per kWh	(C)
85					(N)
Secondary	0.000	0.009	0.009	¢ per kWh(1)	
Primary	0.000	0.009	0.009	¢ per kWh(1)	(N)
87					
Secondary	0.000	0.009	0.009	¢ per kWh(1)	
Primary	0.000	0.009	0.009	¢ per kWh(1)	
Subtransmission	0.000	0.009	0.009	¢ per kWh(1)	
89					
Secondary	0.000	0.009	0.009	¢ per kWh	
Primary	0.000	0.009	0.009	¢ per kWh	
Subtransmission	0.000	0.009	0.009	¢ per kWh	
91	0.000	0.009	0.009	¢ per kWh	
92	0.000	0.009	0.009	¢ per kWh	
93	0.000	0.009	0.009	¢ per kWh	
94	0.000	0.009	0.009	¢ per kWh	
485					(C)
Secondary	0.000	0.009	0.009	¢ per kWh	
Primary	0.000	0.009	0.009	¢ per kWh	
489					
Secondary	0.000	0.009	0.009	¢ per kWh	
Primary	0.000	0.009	0.009	¢ per kWh	
Subtransmission	0.000	0.009	0.009	¢ per kWh	

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

SCHEDULE 105 (Concluded)

ADJUSTMENT RATES (Continued)

Schedule	Part A	Part B	Adjustment Rate		
515	0.000	0.000	0.000	¢ per kWh	
532	0.000	0.000	0.000	¢ per kWh	
538	0.000	0.009	0.009	¢ per kWh	
549	0.000	0.009	0.009	¢ per kWh	
575					
Secondary	0.000	0.009	0.009	¢ per kWh(1)	
Primary	0.000	0.009	0.009	¢ per kWh(1)	
Subtransmission	0.000	0.009	0.009	¢ per kWh(1)	
576R					
Secondary	0.000	0.009	0.009	¢ per kWh	
Primary	0.000	0.009	0.009	¢ per kWh	
Subtransmission	0.000	0.009	0.009	¢ per kWh	
583	0.000	0.009	0.009	¢ per kWh	(C)
585					(N)
Secondary	0.000	0.009	0.009	¢ per kWh	
Primary	0.000	0.009	0.009	¢ per kWh(1)	(N)
589					
Secondary	0.000	0.009	0.009	¢ per kWh	
Primary	0.000	0.009	0.009	¢ per kWh	
Subtransmission	0.000	0.009	0.009	¢ per kWh	
591	0.000	0.009	0.009	¢ per kWh	
592	0.000	0.009	0.009	¢ per kWh	
594	0.000	0.009	0.009	¢ per kWh	

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

SCHEDULE 109
ENERGY EFFICIENCY FUNDING ADJUSTMENT

PURPOSE

To fund the acquisition of additional Energy Efficiency Measures (EEMs) for the benefit of the Company's customers pursuant to the Oregon Renewable Energy Act, Section 46 through programs administered by the Energy Trust of Oregon (ETO).

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 (SDC). Customers so exempted will not be charged for nor directly benefit from the energy efficiency measures funded by this schedule.

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.

DISBURSEMENT OF FUNDS

All funds collected under this schedule less an allowance for uncollectible expenses will be distributed to the ETO on a monthly basis.

ENERGY EFFICIENCY ADJUSTMENT

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

Schedule	Adjustment Rate	
7	0.147 ¢ per kWh	**(N)**
12	0.147 ¢ per kWh	
15	0.256 ¢ per kWh	
32	0.138 ¢ per kWh	
38	0.145 ¢ per kWh	
47	0.161 ¢ per kWh	
49	0.115 ¢ per kWh	

SCHEDULE 109 (Continued)

ENERGY EFFICIENCY ADJUSTMENT (Continued)

Schedule	Adjustment Rate		
75			
Secondary	0.100	¢ per kWh	
Primary	0.100	¢ per kWh	
Subtransmission	0.100	¢ per kWh	
76R			
Secondary	0.100	¢ per kWh	
Primary	0.100	¢ per kWh	
Subtransmission	0.100	¢ per kWh	
83	0.114	¢ per kWh	**(C)**
85			**(N)**
Secondary	0.114	¢ per kWh	
Primary	0.114	¢ per kWh	**(N)**
87			
Secondary	0.100	¢ per kWh	
Primary	0.100	¢ per kWh	
Subtransmission	0.100	¢ per kWh	
89			
Secondary	0.100	¢ per kWh	
Primary	0.100	¢ per kWh	
Subtransmission	0.100	¢ per kWh	
91	0.228	¢ per kWh	
92	0.115	¢ per kWh	
93	0.223	¢ per kWh	
94	0.115	¢ per kWh	**(C)**
485			
Secondary	0.114	¢ per kWh	
Primary	0.114	¢ per kWh	

SCHEDULE 109 (Concluded)

ENERGY EFFICIENCY ADJUSTMENT (Continued)

Schedule	Adjustment Rate	
489		
Secondary	0.100	¢ per kWh
Primary	0.100	¢ per kWh
Subtransmission	0.100	¢ per kWh
515	0.256	¢ per kWh
532	0.138	¢ per kWh
538	0.145	¢ per kWh
549	0.115	¢ per kWh
575		
Secondary	0.100	¢ per kWh
Primary	0.100	¢ per kWh
Subtransmission	0.100	¢ per kWh
576R		
Secondary	0.100	¢ per kWh
Primary	0.100	¢ per kWh
Subtransmission	0.100	¢ per kWh
583	0.114	¢ per kWh (C)
585		(N)
Secondary	0.114	¢ per kWh
Primary	0.114	¢ per kWh (N)
589		
Secondary	0.100	¢ per kWh
Primary	0.100	¢ per kWh
Subtransmission	0.100	¢ per kWh
591	0.228	¢ per kWh
592	0.115	¢ per kWh
594	0.115	¢ per kWh

TERM

This Schedule will terminate on December 31, 2012, subject to review by the Company completed by September 2009 regarding the efficacy of continued funding under this schedule for calendar years 2010 through 2012.

SCHEDULE 110 (Continued)

ENERGY EFFICIENCY CUSTOMER SERVICE ADJUSTMENT

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

Schedule	Adjustment Rate	
7	0.003 ¢ per kWh	
12	0.003 ¢ per kWh	**(N)**
15	0.006 ¢ per kWh	
32	0.003 ¢ per kWh	
38	0.003 ¢ per kWh	
47	0.003 ¢ per kWh	
49	0.002 ¢ per kWh	
75		
Secondary	0.002 ¢ per kWh	
Primary	0.002 ¢ per kWh	
Subtransmission	0.002 ¢ per kWh	
76R		
Secondary	0.002 ¢ per kWh	
Primary	0.002 ¢ per kWh	
Subtransmission	0.002 ¢ per kWh	**(C)**
83	0.003 ¢ per kWh	**(N)**
85		
Secondary	0.003 ¢ per kWh	
Primary	0.003 ¢ per kWh	**(N)**
87		
Secondary	0.005 ¢ per kWh	
Primary	0.005 ¢ per kWh	
Subtransmission	0.005 ¢ per kWh	
89		
Secondary	0.002 ¢ per kWh	
Primary	0.002 ¢ per kWh	
Subtransmission	0.002 ¢ per kWh	
91	0.005 ¢ per kWh	
92	0.002 ¢ per kWh	

SCHEDULE 110 (Continued)

ENERGY EFFICIENCY CUSTOMER SERVICE ADJUSTMENT (Continued)

Schedule	Adjustment Rate	
93	0.005 ¢ per kWh	
94	0.002 ¢ per kWh	
485		(C)
Secondary	0.003 ¢ per kWh	
Primary	0.003 ¢ per kWh	
489		
Secondary	0.002 ¢ per kWh	
Primary	0.002 ¢ per kWh	
Subtransmission	0.002 ¢ per kWh	
515	0.006 ¢ per kWh	
532	0.003 ¢ per kWh	
538	0.003 ¢ per kWh	
549	0.002 ¢ per kWh	
575		
Secondary	0.002 ¢ per kWh	
Primary	0.002 ¢ per kWh	
Subtransmission	0.002 ¢ per kWh	
576R		
Secondary	0.002 ¢ per kWh	
Primary	0.002 ¢ per kWh	
Subtransmission	0.002 ¢ per kWh	(C)
583	0.003 ¢ per kWh	(N)
585		
Secondary	0.003 ¢ per kWh	(N)
Primary	0.003 ¢ per kWh	
589		
Secondary	0.002 ¢ per kWh	
Primary	0.002 ¢ per kWh	
Subtransmission	0.002 ¢ per kWh	

SCHEDULE 111
ADVANCED METERING INFRASTRUCTURE

PURPOSE

To recover from Customers the revenue requirement impact of newly installed Advanced Metering Infrastructure (AMI), less Operations and Maintenance (O & M) cost savings, plus the accelerated depreciation for meters that AMI will replace.

APPLICABLE

To all bills for electric service calculated under all rate schedules listed below.

ADJUSTMENT RATE

The Adjustment Rates, applicable for service on and after June 1, 2008, will be:

Schedule	Adjustment Rate		
7	0.000	¢ per kWh	(R)
12	0.000	¢ per kWh	(N)
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	
76R			
Secondary	0.000	¢ per kWh	
Primary	0.000	¢ per kWh	
Subtransmission	0.000	¢ per kWh	(R)(C)
83	0.000	¢ per kWh	(N)
85			
Secondary	0.000	¢ per kWh	
Primary	0.000	¢ per kWh	(N)

SCHEDULE 111 (Continued)

ADJUSTMENT RATES (Continued)

Schedule	Adjustment Rate		
87			(R)
Secondary	0.000	¢ per kWh	
Primary	0.000	¢ per kWh	
Subtransmission	0.000	¢ per kWh	
89			
Secondary	0.000	¢ per kWh	
Primary	0.000	¢ per kWh	
Subtransmission	0.000	¢ per kWh	
93	0.000	¢ per kWh	(C)
485			
Secondary	0.000	¢ per kWh	
Primary	0.000	¢ per kWh	
489			
Secondary	0.000	¢ per kWh	
Primary	0.000	¢ per kWh	
Subtransmission	0.000	¢ per kWh	
532	0.000	¢ per kWh	
538	0.000	¢ per kWh	
549	0.000	¢ per kWh	
575			
Secondary	0.000	¢ per kWh	
Primary	0.000	¢ per kWh	
Subtransmission	0.000	¢ per kWh	
576R			
Secondary	0.000	¢ per kWh	
Primary	0.000	¢ per kWh	
Subtransmission	0.000	¢ per kWh	(R)

SCHEDULE 111 (Concluded)

ADJUSTMENT RATES (Continued)

583	0.000	¢ per kWh	**(R)(C)**
585			
Secondary	0.000	¢ per kWh	**(N)**
Primary	0.000	¢ per kWh	**(N)**
589			
Secondary	0.000	¢ per kWh	**(R)**
Primary	0.000	¢ per kWh	
Subtransmission	0.000	¢ per kWh	**(R)**

SPECIAL CONDITIONS

1. This Schedule will terminate within six months or less of the effective date if Systems Acceptance Testing is not successful or alternatively if the Company does not commence mass deployment of meters within 75 days of completion of Systems Acceptance Testing.

2. This Schedule may be temporarily suspended in order to resolve specific issues identified during Systems Acceptance Testing. The Company must file an application to suspend at least 45 days before the termination deadline specified in Special Condition 1.

TERM

This adjustment schedule will terminate December 31, 2010.

SCHEDULE 121
SELECTIVE WATER WITHDRAWAL ADJUSTMENT

PURPOSE

This schedule recovers the fixed generation revenue requirement of the Company's Selective Water Withdrawal project on the Deschutes River located at the Round Butte Dam. Approval of this tariff adjustment will be considered a Commission revision of the Company's ratio of net revenues to gross revenues and effective tax rate for purposes of OAR 860-22-0041.

AVAILABLE

In all territory served by the Company

APPLICABLE

To all bills for Electricity Service served under the following rate schedules 7, 12, 15, 32, 38, 47, 49, 75, 83, 85, 87, 89, 91, 92, 93 and 94. **(C)**

ADJUSTMENT RATE

Schedule	Adjustment Rate	
7	0.000 ¢ per kWh	**(R)**
12	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	**(C)(R)**
85		**(N)**
Secondary	0.000 ¢ per kWh	
Primary	0.000 ¢ per kWh	**(N)**
87		**(R)**
Secondary	0.000 ¢ per kWh	
Primary	0.000 ¢ per kWh	
Subtransmission	0.000 ¢ per kWh	
89		
Secondary	0.000 ¢ per kWh	
Primary	0.000 ¢ per kWh	
Subtransmission	0.000 ¢ per kWh	**(R)**

SCHEDULE 121 (Concluded)

ADJUSTMENT RATE (Continued)

Schedule	Adjustment Rate		
91	0.000	¢ per kWh	(R)
92	0.000	¢ per kWh	
93	0.000	¢ per kWh	
94	0.000	¢ per kWh	(R)

SPECIAL CONDITIONS

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

2. The rates in this schedule will be added to the applicable rate schedules' Cost of Service Energy Charges for purposes of calculating the Schedule 128 Transition Adjustment.

3. Collections under this schedule will terminate at such time as the costs are included in base rates.

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 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).

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all bills for Electricity Service except Schedules 9, 76, 485, 489, and 576. This schedule is not applicable to direct access customers after December 31, 2010. **(C)**

ADJUSTMENT RATE

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

Schedule			
7	0.227	¢ per kWh	
12	0.227	¢ per kWh	**(N)**
15	0.211	¢ per kWh	
32	0.227	¢ per kWh	
38	0.229	¢ per kWh	
47	0.210	¢ per kWh	
49	0.211	¢ per kWh	
75			
Secondary	0.226	¢ per kWh	
Primary	0.215	¢ per kWh	
Subtransmission	0.209	¢ per kWh	
83	0.225	¢ per kWh	**(C)**
85			**(N)**
Secondary	0.225	¢ per kWh	|
Primary	0.218	¢ per kWh	**(N)**

SCHEDULE 122 (Continued)

ADJUSTMENT RATE (Continued)

Schedule			
87			
	Secondary	0.226	¢ per kWh
	Primary	0.215	¢ per kWh
	Subtransmission	0.209	¢ per kWh
89			
	Secondary	0.226	¢ per kWh
	Primary	0.215	¢ per kWh
	Subtransmission	0.209	¢ per kWh
91		0.211	¢ per kWh
92		0.221	¢ per kWh
93		0.225	¢ per kWh
94		0.221	¢ per kWh
515		0.211	¢ per kWh
532		0.227	¢ per kWh
538		0.229	¢ per kWh
549		0.211	¢ per kWh
575			
	Secondary	0.226	¢ per kWh
	Primary	0.215	¢ per kWh
	Subtransmission	0.209	¢ per kWh (C)
583		0.225	¢ per kWh
585			(N)
	Secondary	0.225	¢ per kWh
	Primary	0.218	¢ per kWh (N)
589			
	Secondary	0.226	¢ per kWh
	Primary	0.215	¢ per kWh
	Subtransmission	0.209	¢ per kWh
591		0.211	¢ per kWh
592		0.221	¢ per kWh
594		0.221	¢ per kWh

SCHEDULE 123
SALES NORMALIZATION 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 5.842 cents/kWh for Schedule 7 **(I)** and 5.593 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 $51.29 per month for Schedule 7 and $79.50 per month for Schedules 32 and **(I)** 532 to the numbers of active Schedule 7 and Schedule 32 and 532 Customers, respectively, for each month.

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

SCHEDULE 123 (Continued)

NONRESIDENTIAL LOST REVENUE RECOVERY ADJUSTMENT (LRRA)

The Nonresidential Lost Revenue Recovery Adjustment is applicable to all customers except those served under Schedules 7, 32 and 532 or as otherwise exempted above. Nonresidential Lost Revenue Recovery amounts will be equal to the reduction in distribution, transmission, and fixed generation revenues due to the reduction in kWh sales as reported to the Company by the Energy Trust of Oregon, resulting from EEMs implemented during prior calendar years attributable to EEM funding incremental to Schedule 108, adjusted for EEM program kWh savings incorporated into the test year load forecast used to determine base rates. 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 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 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 the reduction in kWh sales resulting from ETO-reported EEMs and 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 4.011 cents per kWh. **(I)**

SNA and LRRA BALANCING ACCOUNTS

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

SCHEDULE 123 (Continued)

SALES NORMALIZATION ADJUSTMENT (SNA)

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

Schedule	Adjustment Rate	
7	0.000 ¢ per kWh	
12	0.000 ¢ per kWh	**(N)**
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	
76R		
Secondary	0.000 ¢ per kWh	
Primary	0.000 ¢ per kWh	
Subtransmission	0.000 ¢ per kWh	
83	0.000 ¢ per kWh	**(C)**
85		**(N)**
Secondary	0.000 ¢ per kWh	
Primary	0.000 ¢ per kWh	**(N)**
87		
Secondary	0.000 ¢ per kWh	
Primary	0.000 ¢ per kWh	
Subtransmission	0.000 ¢ per kWh	
89		
Secondary	0.000 ¢ per kWh	
Primary	0.000 ¢ per kWh	
Subtransmission	0.000 ¢ per kWh	

SCHEDULE 123 (Continued)

SALES NORMALIZATION ADJUSTMENT (SNA) (Continued)

Schedule	Adjustment Rate	
91	0.000 ¢ per kWh	(M)
92	0.000 ¢ per kWh	
93	0.000 ¢ per kWh	
94	0.000 ¢ per kWh	(M)
485		(C)
Secondary	0.000 ¢ per kWh	
Primary	0.000 ¢ per kWh	
489		
Secondary	0.000 ¢ per kWh	
Primary	0.000 ¢ per kWh	
Subtransmission	0.000 ¢ per kWh	
515	0.000 ¢ per kWh	
532	0.000 ¢ per kWh	
538	0.000 ¢ per kWh	
549	0.000 ¢ per kWh	
575		
Secondary	0.000 ¢ per kWh	
Primary	0.000 ¢ per kWh	
Subtransmission	0.000 ¢ per kWh	
576R		
Secondary	0.000 ¢ per kWh	
Primary	0.000 ¢ per kWh	
Subtransmission	0.000 ¢ per kWh	
583	0.000 ¢ per kWh	(C)
585		(N)
Secondary	0.000 ¢ per kWh	
Primary	0.000 ¢ per kWh	(N)

(T)

SCHEDULE 123 (Continued)

SALES NORMALIZATION ADJUSTMENT (SNA) (Continued) (M)

Schedule	Adjustment Rate	
589		
Secondary	0.000	¢ per kWh
Primary	0.000	¢ per kWh
Subtransmission	0.000	¢ per kWh
591	0.000	¢ per kWh
592	0.000	¢ per kWh
594	0.000	¢ per kWh (M)

TIME AND MANNER OF FILING

Commencing in 2010, the Company will submit to the Commission the following information by April 1 of each year:

1. The proposed price changes to this Schedule to be effective on June 1st of the submittal year based on a) the amount in the SNA Balancing Account at the end of the 12-month period commencing on February 1, 2009, and 2010, and at the end of each succeeding (C) calendar year and b) the amount in the LRRA Balancing Account at the end of the (C) previous calendar year.

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

3. The status of the SNA and LRRA Balancing Accounts.

SCHEDULE 123 (Concluded)

SPECIAL CONDITIONS **(M)**

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

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

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

(D)

(M)

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 bills for Electricity Service served under the following rate schedules 7, 12, 15, 32, 38, 47, **(C)**
49, 75, 83, 85, 87, 89, 91, 92, 93 and 94. **(C)**

NET VARIABLE POWER COSTS

Net Variable Power Costs (NVPC) are the power costs for energy generated and purchased. NVPC are the net cost of fuel, fuel 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.
- Forward market prices for both gas and electricity.
- Projected loads.
- Contracts for the purchase or sale of power and fuel.
- Thermal plant variable operation and maintenance. **(N)**
- Changes in hedges, options, and other financial instruments used to serve retail load.
- Transportation contracts and other fixed transportation costs.
- No other changes or updates will be made in the annual filings under this schedule.

CHANGES IN NET VARIABLE POWER COSTS

Changes in NVPC for purposes of rate determination under this schedule are the projected NVPC as determined in the Annual Power Cost Update less the NVPC revenues that would occur at the NVPC prices determined in the Company's most recent general rate case, adjusted for a revenue sensitive cost factor of 1.0352. **(I)**

SCHEDULE 125 (Continued)

FILING AND EFFECTIVE DATE

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

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

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

RATE ADJUSTMENT

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

ADJUSTMENT RATES

Schedule		Part A ¢ per kWh	
7		0.000	**(I)**
12		0.000	**(N)**
15		0.000	
32		0.000	
38	Large Nonresidential	0.000	
47		0.000	
49		0.000	
75	Secondary	0.000 [1]	
	Primary	0.000 [1]	
	Subtransmission	0.000 [1]	
83		0.000	**(I)(C)**
85	Secondary	0.000	**(N)**
	Primary	0.000	**(N)**
87	Secondary	0.000	**(I)**
	Primary	0.000	
	Subtransmission	0.000	**(I)**

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

Portland General Electric Company **Fifth Revision of Sheet No. 125-3**
P.U.C. Oregon No. E-18 **Canceling Fourth Revision of Sheet No. 125-3**

SCHEDULE 125 (Concluded)

ADJUSTMENT RATES (Continued)

Schedule		Part A ¢ per kWh	
89	Secondary	0.000	(I)
	Primary	0.000	
	Subtransmission	0.000	
91		0.000	
92		0.000	
93		0.000	
94		0.000	(I)

SPECIAL CONDITIONS

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

SCHEDULE 126
ANNUAL POWER COST VARIANCE MECHANISM

PURPOSE

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

APPLICABLE

To all Customers for Electricity Service except those who were served on Schedule 76R and 576R, 485, 489, 515, 532, 538, 549, 583, 585, 589, 591, 592 and 594, or served under Schedules 83, 85 or 89 Daily Price Option for the entire calendar year that the Annual Power Cost Variance accrued. Customers served on Schedules 538, 583, 585, 589, 591 and 592 who received the Schedule 128 Balance of Year Transition Adjustment will be subject to this adjustment. **(C)** | **(C)**

ANNUAL POWER COST VARIANCE **(T)**

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

POWER COST VARIANCE ACCOUNT

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

Any balance in the PCV Account will be amortized to rates over a period determined by the Commission. Annually, the Company will propose to the Commission PCV Adjustment Rates that will amortize the PCV to rates over a period recommended by the Company. The amount accruing to Customers, whether positive or negative, will be multiplied by a revenue sensitive factor of 1.0352 to account for franchise fees, uncollectibles, and OPUC fees. **(I)**

EARNINGS TEST

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

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 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.

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 594 after the November update for the applicable year.

Negative Annual Power Cost Deadband

The Negative Annual Power Cost Deadband is ($10.0 million). **(C)**

Positive Annual Power Cost Deadband

The Positive Annual Power Cost Deadband is $10.0 million. **(C)**

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, fuel 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, and 91 **(C)** Energy pricing options other than Cost of Service and the Energy Charge revenues from the Market Based Pricing Option from Schedules 485 and 489 as an offset to **(C)** NVPC.
- NVPC shall be adjusted as needed to comply with Order 07-015 that states that ancillary services, the revenues from sales as well as the costs from the services, should also be taken into account in the mechanism.
- Actual NVPC will be increased to include the value of the energy associated with those Customers that received the Schedule 128 Balance of Year Transition Adjustment for the period during the year that the Customers received the Schedule 128 adjustment.

ADJUSTMENT AMOUNT

The amount accruing to the Power Cost Variance Account, whether positive or negative will be multiplied by a revenue sensitive factor of 1.0352 to account for franchise fees, uncollectables, and **(I)** 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.

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	(0.007) ¢ per kWh	**(N)**
12	(0.007) ¢ per kWh	
15	(0.007) ¢ per kWh	
32	(0.007) ¢ per kWh	
38	(0.007) ¢ per kWh	
47	(0.007) ¢ per kWh	
49	(0.007) ¢ per kWh	
75		
Secondary	(0.007) ¢ per kWh(1)	
Primary	(0.007) ¢ per kWh(1)	
Subtransmission	(0.007) ¢ per kWh(1)	
83	(0.007) ¢ per kWh	**(C)**
85		**(N)**
Secondary	(0.007) ¢ per kWh	|
Primary	(0.007) ¢ per kWh(1)	**(N)**
87		
Secondary	(0.007) ¢ per kWh(1)	
Primary	(0.007) ¢ per kWh(1)	
Subtransmission	(0.007) ¢ per kWh(1)	
89		
Secondary	(0.007) ¢ per kWh	
Primary	(0.007) ¢ per kWh	
Subtransmission	(0.007) ¢ 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 126 (Continued)

POWER COST VARIANCE RATES (Continued)

Schedule	Adjustment Rate	
91	(0.007) ¢ per kWh	
92	(0.007) ¢ per kWh	
93	(0.007) ¢ per kWh	
94	(0.007) ¢ per kWh	
485		(C)
Secondary	(0.007) ¢ per kWh(2)	
Primary	(0.007) ¢ per kWh(2)	
489		
Secondary	(0.007) ¢ per kWh(2)	
Primary	(0.007) ¢ per kWh(2)	
Subtransmission	(0.007) ¢ per kWh(2)	
515	(0.007) ¢ per kWh(2)	
532	(0.007) ¢ per kWh(2)	
538	(0.007) ¢ per kWh(2)	
549	(0.007) ¢ per kWh(2)	
575		
Secondary	(0.007) ¢ per kWh(1)	
Primary	(0.007) ¢ per kWh(1)	
Subtransmission	(0.007) ¢ per kWh(1)	
583	(0.007) ¢ per kWh(2)	(C)
585	(0.007) ¢ per kWh(2)	(N)
Seconday	(0.007) ¢ per kWh(2)	
Primary	(0.007) ¢ per kWh(2)	(N)
589		
Secondary	(0.007) ¢ per kWh(2)	
Primary	(0.007) ¢ per kWh(2)	
Subtransmission	(0.007) ¢ per kWh(2)	
591	(0.007) ¢ per kWh(2)	
592	(0.007) ¢ per kWh(2)	
594	(0.007) ¢ 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 or 91; or Direct Access service on Schedules 515, 532, 538, 549, 575, 583, 585, 589, 591, 592, 594. This Schedule is not applicable to Customers served on Schedules 485 and 489. (C) (C)

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 2011, the Annual Short-Term Transition Adjustment Rate will be applied to their bills for service effective on and after January 1, 2011: (C) (C)

Schedule		Annual ¢ per kWh [(1)]	
32		0.565	(R)
38		0.310	
75	Secondary On-Peak	(0.035) [(2)]	
	Secondary Off-Peak	0.089 [(2)]	
	Primary On-Peak	0.005 [(2)]	
	Primary Off-Peak	0.070 [(2)]	
	Subtransmission On-Peak	0.011 [(2)]	
	Subtransmission Off-Peak	0.049 [(2)]	
83		0.517	(R)(C)
85	Secondary On-Peak	0.199	(N)
	Secondary Off-Peak	0.301	
	Primary On-Peak	0.213	
	Primary Off-Peak	0.279	(N)

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

Portland General Electric Company **Eighth Revision of Sheet No. 128-2**
P.U.C. Oregon No. E-18 **Canceling Seventh Revision of Sheet No. 128-2**

SCHEDULE 128 (Continued)

ANNUAL SHORT-TERM TRANSITION ADJUSTMENT RATE (Continued)

Schedule		Annual ¢ per kWh (1)	
89	Secondary On-Peak	(0.035)	(R)
	Secondary Off-Peak	0.089	
	Primary On-Peak	0.005	
	Primary Off-Peak	0.070	
	Subtransmission On-Peak	0.011	
	Subtransmission Off-Peak	0.049	
91		0.026	
515		0.026	
532		0.565	
538		0.310	(R)
549		1.671	(I)
575	Secondary On-Peak	(0.035) (2)	(R)
	Secondary Off-Peak	0.089 (2)	
	Primary On-Peak	0.005 (2)	
	Primary Off-Peak	0.070 (2)	
	Subtransmission On-Peak	0.011 (2)	
	Subtransmission Off-Peak	0.049 (2)	(R)
583		0.517	(C)
585	Secondary On-Peak	0.199	(N)
	Secondary Off-Peak	0.301	
	Primary On-Peak	0.213	
	Primary Off-Peak	0.279	(N)
589	Secondary On-Peak	(0.035)	(R)
	Secondary Off-Peak	0.089	
	Primary On-Peak	0.005	
	Primary Off-Peak	0.070	
	Subtransmission On-Peak	0.011	
	Subtransmission Off-Peak	0.049	
591		0.026	
592		(0.116)	
594		(0.116)	(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 will be posted by the Company two months 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.

Advice No. 10-04
Issued February 16, 2010
Maria M. Pope, Senior Vice President

Effective for service
on and after March 18, 2010

Portland General Electric Company **Eighth Revision of Sheet No. 128-4**
P.U.C. Oregon No. E-18 **Canceling Seventh Revision of Sheet No. 128-4**

SCHEDULE 128 (Continued)

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

Schedule		¢ per kWh (2)	
38		0.000	
75	Secondary On-Peak	0.000 (3)	
	Secondary Off-Peak	0.000 (3)	
	Primary On-Peak	0.000 (3)	
	Primary Off-Peak	0.000 (3)	
	Subtransmission On-Peak	0.000 (3)	
	Subtransmission Off-Peak	0.000 (3)	
83		0.000	(C)
85	Secondary On-Peak	0.000 (3)	(N)
	Secondary Off-Peak	0.000 (3)	
	Primary On-Peak	0.000 (3)	
	Primary Off-Peak	0.000 (3)	(N)
89	Secondary On-Peak	0.000	
	Secondary Off-Peak	0.000	
	Primary On-Peak	0.000	
	Primary Off-Peak	0.000	
	Subtransmission On-Peak	0.000	
	Subtransmission Off-Peak	0.000	
91		0.000	
538		0.000	
575	Secondary On-Peak	0.000 (3)	
	Secondary Off-Peak	0.000 (3)	
	Primary On-Peak	0.000 (3)	
	Primary Off-Peak	0.000 (3)	
	Subtransmission On-Peak	0.000 (3)	
	Subtransmission Off-Peak	0.000 (3)	
583		0.000	(C)
585	Secondary On-Peak	0.000 (3)	(N)
	Secondary Off-Peak	0.000 (3)	
	Primary On-Peak	0.000 (3)	
	Primary Off-Peak	0.000 (3)	(N)
589	Secondary On-Peak	0.000	
	Secondary Off-Peak	0.000	
	Primary On-Peak	0.000	
	Primary Off-Peak	0.000	
	Subtransmission On-Peak	0.000	
	Subtransmission Off-Peak	0.000	
591		0.000	
592		0.000	
			(C)

(1) Applicable April 1, 2011 through December 31, 2011.
(2) Not applicable to Customers served on Cost of Service.
(3) Applicable only to the Baseline and Scheduled Maintenance Energy.

SCHEDULE 128 (Continued)

Third Quarter – July 1st Balance of Year Adjustment Rate (1)

Schedule		¢ per kWh (2)	
38		0.000	
75	Secondary On-Peak	0.000 (3)	
	Secondary Off-Peak	0.000 (3)	
	Primary On-Peak	0.000 (3)	
	Primary Off-Peak	0.000 (3)	
	Subtransmission On-Peak	0.000 (3)	
	Subtransmission Off-Peak	0.000 (3)	
83		0.000	(C)
85	Secondary On-Peak	0.000 (3)	(N)
	Secondary Off-Peak	0.000 (3)	
	Primary On-Peak	0.000 (3)	(N)
	Primary Off-Peak	0.000 (3)	
89	Secondary On-Peak	0.000	
	Secondary Off-Peak	0.000	
	Primary On-Peak	0.000	
	Primary Off-Peak	0.000	
	Subtransmission On-Peak	0.000	
	Subtransmission Off-Peak	0.000	
91		0.000	
538		0.000	
575	Secondary On-Peak	0.000 (3)	
	Secondary Off-Peak	0.000 (3)	
	Primary On-Peak	0.000 (3)	
	Primary Off-Peak	0.000 (3)	
	Subtransmission On-Peak	0.000 (3)	
	Subtransmission Off-Peak	0.000 (3)	(C)
583		0.000	(N)
585	Secondary On-Peak	0.000 (3)	
	Secondary Off-Peak	0.000 (3)	
	Primary On-Peak	0.000 (3)	(N)
	Primary Off-Peak	0.000 (3)	
589	Secondary On-Peak	0.000	
	Secondary Off-Peak	0.000	
	Primary On-Peak	0.000	
	Primary Off-Peak	0.000	
	Subtransmission On-Peak	0.000	
	Subtransmission Off-Peak	0.000	
591		0.000	
592		0.000	

(C)

(1) Applicable July 1, 2011 through December 31, 2011.
(2) Not applicable to Customers served on Cost of Service.
(3) Applicable only to the Baseline and Scheduled Maintenance Energy.

Portland General Electric Company **Sixth Revision of Sheet No. 128-6**
P.U.C. Oregon No. E-18 **Canceling Fifth Revision of Sheet No. 128-6**

SCHEDULE 128 (Concluded)

Fourth Quarter – October 1st Balance of Year Adjustment Rate [1]

Schedule		¢ per kWh [2]	
38		0.000	
75	Secondary On-Peak	0.000 [3]	
	Secondary Off-Peak	0.000 [3]	
	Primary On-Peak	0.000 [3]	
	Primary Off-Peak	0.000 [3]	
	Subtransmission On-Peak	0.000 [3]	
	Subtransmission Off-Peak	0.000 [3]	
83	Secondary	0.000	(C)
85	Secondary On-Peak	0.000 [3]	(N)
	Secondary Off-Peak	0.000 [3]	
	Primary On-Peak	0.000 [3]	
	Primary Off-Peak	0.000 [3]	(N)
89	Secondary On-Peak	0.000	
	Secondary Off-Peak	0.000	
	Primary On-Peak	0.000	
	Primary Off-Peak	0.000	
	Subtransmission On-Peak	0.000	
	Subtransmission Off-Peak	0.000	
91		0.000	
538		0.000	
575	Secondary On-Peak	0.000 [3]	
	Secondary Off-Peak	0.000 [3]	
	Primary On-Peak	0.000 [3]	
	Primary Off-Peak	0.000 [3]	
	Subtransmission On-Peak	0.000 [3]	
	Subtransmission Off-Peak	0.000 [3]	
583		0.000	(C)
585	Secondary On-Peak	0.000 [3]	(N)
	Secondary Off-Peak	0.000 [3]	
	Primary On-Peak	0.000 [3]	
	Primary Off-Peak	0.000 [3]	(N)
589	Secondary On-Peak	0.000	
	Secondary Off-Peak	0.000	
	Primary On-Peak	0.000	
	Primary Off-Peak	0.000	
	Subtransmission On-Peak	0.000	
	Subtransmission Off-Peak	0.000	
591		0.000	
592		0.000	

(1) Applicable October 1, 2011 through December 31, 2011. (C)
(2) Not applicable to Customers served on Cost of Service.
(3) Applicable only to the Baseline and Scheduled Maintenance Energy.

SCHEDULE 129
LONG-TERM TRANSITION COST ADJUSTMENT

AVAILABLE

In all territory served by the Company.

APPLICABLE

Applicable to Large Nonresidential Customers that have selected service under Schedule 485 and 489. **(C)**

TRANSITION COST ADJUSTMENT

Minimum Five Year Opt-Out

For Enrollment Period A (2002); No Longer Applicable **(C)**

0.000 ¢ per kWh after December 31, 2007

For Enrollment Period B (2003); No Longer Applicable **(C)** **(D)**

0.000 ¢ per kWh after December 31, 2008

For Enrollment Period C (2004); No Longer Applicable **(C)** **(D)**

For Enrollment Period D (2005); No Longer Applicable **(C)** **(D)**

SCHEDULE 129 (Continued)

TRANSITION COST ADJUSTMENT (Continued)
Three Year Opt-Out

This option was not available during Enrollment Periods A and B.

For Enrollment Period C (2004): No longer applicable

For Enrollment Period D (2005), No Longer Applicable **(C)**
(D)

For Enrollment Period E (2006); No Longer Applicable **(C)**

For Enrollment Period F (2007); No Longer Applicable **(C)**

For Enrollment Period G (2008), the Transition Cost Adjustment will be:

(1.043) ¢ per kWh	January 1, 2009 through December 31, 2009
(0.994) ¢ per kWh	January 1, 2010 through December 31, 2010
(0.720) ¢ per kWh	January 1, 2011 through December 31, 2011

For Enrollment Period H (2009), the Transition Cost Adjustment will be:

0.673 ¢ per kWh	January 1, 2010 through December 31, 2010
0.415 ¢ per kWh	January 1, 2011 through December 31, 2011
0.473 ¢ per kWh	January 1, 2012 through December 31, 2012

SCHEDULE 129 (Concluded)

SPECIAL CONDITIONS

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

2. Annually, changes in fixed generation revenues resulting from either return to or departure from Cost of Service pricing by Schedule 485 and 489 customers relative to the Company's most recent general rate case will be incorporated into the System Usage Charges of the Large Nonresidential Rate Schedules 75, 76R, 85, 89, 485, 489, 575, 576R, 585, and 589. Such adjustment to the System Usage or Distribution Charges will be made at the time the Company files final rates for Schedule 125, and will be effective on January 1st of the following calendar year. The adjustment to the System Usage Charge resulting from changes in fixed generation revenues shall not result in a rate increase or decrease to Schedules 85, and 89 of more than 2 percent. For purposes of calculating the percent change in rates, Schedule 125 prices with and without the increased/decreased Schedules 485 and 489 participating load will be determined. **(C)** **(C)** **(C)** **(C)**

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

Schedule		¢ per kWh	
			(D)
85	Secondary	2.279	**(N)**
	Primary	2.204	**(N)**
89	Secondary	2.184	**(I)**
	Primary	2.092	|
	Subtransmission	2.056	**(I)**

TERM

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

SCHEDULE 133
COLSTRIP TAX and ROYALTY PAYMENT ADJUSTMENT

PURPOSE

To recover from Customers taxes and royalty payments retroactively assessed by the U.S. Department of Interior and the Montana Department of Revenue.

APPLICABLE

To all bills for electric service calculated under all rate schedules listed below.

ADJUSTMENT RATE

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

Schedule	Adjustment Rate		
7	0.011	¢ per kWh	
12	0.011	¢ per kWh	(N)
15	0.011	¢ per kWh	
32	0.011	¢ per kWh	
38	0.011	¢ per kWh	
47	0.011	¢ per kWh	
49	0.011	¢ per kWh	
75			
Secondary	0.011	¢ per kWh	
Primary	0.011	¢ per kWh	
Subtransmission	0.011	¢ per kWh	
76R			
Secondary	0.011	¢ per kWh	
Primary	0.011	¢ per kWh	
Subtransmission	0.011	¢ per kWh	
83	0.011	¢ per kWh	(C)
85		¢ per kWh	(N)
Secondary	0.011	¢ per kWh	
Primary	0.011	¢ per kWh	(N)

SCHEDULE 133 (Continued)

ADJUSTMENT RATES (Continued)

Schedule	Adjustment Rate		
87			(M)
Secondary	0.011	¢ per kWh	
Primary	0.011	¢ per kWh	
Subtransmission	0.011	¢ per kWh	(M)
89			
Secondary	0.011	¢ per kWh	
Primary	0.011	¢ per kWh	
Subtransmission	0.011	¢ per kWh	
91	0.011	¢ per kWh	
92	0.011	¢ per kWh	
93	0.011	¢ per kWh	
94	0.011	¢ per kWh	
485			(C)
Secondary	0.011	¢ per kWh	
Primary	0.011	¢ per kWh	
489			
Secondary	0.011	¢ per kWh	
Primary	0.011	¢ per kWh	
Subtransmission	0.011	¢ per kWh	
515	0.011	¢ per kWh	
532	0.011	¢ per kWh	
538	0.011	¢ per kWh	
549	0.011	¢ per kWh	
575			
Secondary	0.011	¢ per kWh	
Primary	0.011	¢ per kWh	
Subtransmission	0.011	¢ per kWh	

SCHEDULE 133 (Concluded)

ADJUSTMENT RATES (Continued)

Schedule	Adjustment Rate		
576R			(M)
Secondary	0.011	¢ per kWh	
Primary	0.011	¢ per kWh	
Subtransmission	0.011	¢ per kWh	
583	0.011	¢ per kWh	(M)(C)
585			(N)
Secondary	0.011	¢ per kWh	
Primary	0.011	¢ per kWh	(N)
589			
Secondary	0.011	¢ per kWh	
Primary	0.011	¢ per kWh	
Subtransmission	0.011	¢ per kWh	
591	0.011	¢ per kWh	
592	0.011	¢ per kWh	
594	0.011	¢ per kWh	

BALANCING ACCOUNT

The Company will establish a Balancing Account to record the difference between amounts collected under this schedule and amounts authorized to be recovered. This Balancing Account will accrue interest at the Commission-authorized rate for deferred accounts. The disposition of any over or under-recovery amount will be subject to Commission approval.

TERM

This Schedule will terminate upon full collection of the taxes and royalty payments.

SCHEDULE 141
PENSION ADJUSTMENT MECHANISM

PURPOSE

This schedule recovers or refunds to Customers incremental amounts beyond those in base rates associated with the Company's expense and financing costs of incremental cash contributions related to the Company's employee pension plan funding obligations in compliance with the requirements of the Pension Protection Act of 2006 and FAS 87. This schedule is an "automatic adjustment clause" as defined by ORS 757.210.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all bills for Electricity Service.

ADJUSTMENT RATE

The Adjustment Rate, unless otherwise approved by the Commission, will be effective on January 1st of the applicable calendar year:

Schedule	Adjustment Rate
7	0.000 ¢ per kWh
12	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
76R	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh

SCHEDULE 141 (Continued)

ADJUSTMENT RATE (Continued)

Schedule	Adjustment Rate
83	0.000 ¢ per kWh
85	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
87	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
89	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
91	0.000 ¢ per kWh
92	0.000 ¢ per kWh
93	0.000 ¢ per kWh
94	0.000 ¢ per kWh
485	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
489	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
515	0.000 ¢ per kWh
532	0.000 ¢ per kWh
538	0.000 ¢ per kWh
549	0.000 ¢ per kWh

SCHEDULE 141 (Continued)

ADJUSTMENT RATE (Continued)

Schedule	Adjustment Rate
575	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
576R	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
583	0.000 ¢ per kWh
585	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
589	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
591	0.000 ¢ per kWh
592	0.000 ¢ per kWh
594	0.000 ¢ per kWh

ADJUSTMENT AMOUNT

The adjustment amount is the sum of applicable pension expense, Financing Cost, and the difference between actual and forecast pension expense from the prior period; adjusted by a revenue sensitive cost factor of 1.0352 to account for uncollectibles, franchise fees, and other revenue sensitive costs. For 2011, pension expense and Financing Cost are included in the Company's base rates and the adjustment amount is zero. The Financing Basis becomes part of base rates with each subsequent General Rate Case (GRC).

SCHEDULE 141 (Concluded)

ADJUSTMENT AMOUNT (Continued)

Financing Cost

Financing Cost equal the Financing Basis times the Rate.

Financing Basis

For 2012 and each year thereafter, the Financing Basis is the sum of: (A) the difference between cumulative actual cash contributions and cumulative actual pension expense since the last approved GRC minus the difference between forecast cash contributions and forecast pension expense as included in the last approved GRC, and (B) the difference between forecast cash contributions and forecast pension expense for the effective year.

Rate

The Rate is the Company's cost of capital grossed up for taxes.

TIME AND MANNER OF FILING

For each calendar year the Company will file no later than October 1, the following:

1. Revised rates under this schedule and a transmittal letter that summarizes the basis for the requested rate with an effective date of the following January 1st.

2. Work papers that support the calculation of the Adjustment Amount including: actual and forecast pension expense, cash contributions, Financing Basis, and forecast Financing Cost.

The Company will file the updated rates that are in compliance with the Commission's findings in the proceeding reviewing the October filing.

SCHEDULE 145
BOARDMAN POWER PLANT
OPERATING LIFE ADJUSTMENT

PURPOSE

This schedule establishes the mechanism to implement in rates the revenue requirement effect of a Commission-authorized change in the Boardman Power Plant's currently assumed end of life year of 2040. This schedule is implemented as an "automatic adjustment clause" as defined in ORS 757.210.

APPLICABLE

To all bills for Electricity Service except Schedules 9, 76R, 485, 489 and 576R.

ADJUSTMENT RATES

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

Schedule	Adjustment Rate
7	0.000 ¢ per kWh
12	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 145 (Continued)

ADJUSTMENT RATE (Continued)

Schedule	Adjustment Rate
87	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
89	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
91	0.000 ¢ per kWh
92	0.000 ¢ per kWh
93	0.000 ¢ per kWh
94	0.000 ¢ per kWh
515	0.000 ¢ per kWh
532	0.000 ¢ per kWh
538	0.000 ¢ per kWh
549	0.000 ¢ per kWh
575	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
583	0.000 ¢ per kWh
585	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh

SCHEDULE 145 (Concluded)

ADJUSTMENT RATE (Continued)

Schedule	Adjustment Rate
589	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
591	0.000 ¢ per kWh
592	0.000 ¢ per kWh
594	0.000 ¢ per kWh

DETERMINATION OF ADJUSTMENT AMOUNT

Any revision to this schedule's Adjustment Rates requires Commission authorization (by order, approval of a filing, acknowledgement of an Integrated Resource Plan's Action Plan or approval of a depreciation study) to revise for rate setting and accounting purposes, the end of life assumption of 2040 for the Boardman Power Plant. The revised Adjustment Rates will be set to recover an Adjustment Amount reflecting the change in depreciation revenue requirements.

The Adjustment Amount is the difference between the Boardman Power Plant depreciation/amortization revenue requirement for the year 2011 as determined in UE ___ that reflects a plant end of life date of 2040, and the same depreciation/amortization revenue requirement determination using a plant end of life assumption as ordered by the Commission. The depreciation/amortization revenue requirement change computation will use the Commission-authorized tax rates, revenue sensitive cost rates, rate of return and return on equity rates. Only changes to depreciation expense, amortization expense and related Schedule M and rate base adjustments as of the date of the filing revisions to this rate schedule are included in the depreciation/amortization revenue requirements.

The Adjustment Rates will be updated annually to reflect the subsequent year's change in the Boardman Power Plant deprecation revenue requirement, if the Company has not incorporated the revised depreciable life into base rates in a general rate case or other proceeding.

The reference docket numbers and dates in this schedule will be revised as necessary to a subsequent docket if no change to the Boardman depreciable life occurs prior to a subsequent general rate case order.

TERM

This schedule will terminate at the date that base rates include the revised end of life assumption or when all remaining investment in the Boardman Power Plant has been recovered.

SCHEDULE 300 (Continued)

LINE EXTENSIONS (Rule I)

Line Extension Allowance (Section 1)

Residential Service	$1,514.00 / dwelling unit	
Small Nonresidential Service (Schedules 15, 32 & 47)	$ 0.1129 /estimated annual kWh	
Large Nonresidential Service Secondary Voltage Service (Schedules 38, 49, 83, 85, 89 & 91)	$ 0.0524 /estimated annual kWh	**(C)**
Large Nonresidential Primary voltage service (Schedules 38, 49, 85 & 89)	$ 0.0295 /estimated annual kWh	**(C)**

Trenching or Boring (Section 3)

Trenching and backfilling associated with Service Installation except where General Rules and Regulations require actual cost.

In Residential Subdivisions:	
Short-side service connection up to 30 feet	$ 100.00
Otherwise:	
First 75 feet or less	$ 219.00
Greater than 75 feet	$ 3.80 /foot
Mainline trenching, boring and backfilling	Estimated Actual Cost

Lighting Underground Service Areas[(1)]

Installation of conduit on a wood pole for lighting purposes	$ 75.00 per pole

Additional Services (Section 3)
(applies solely to Residential Subdivisions in Underground Service Areas)

Service Guarantee	$ 100.00
Wasted Trip Charge	$ 100.00
Service Locate Charge	$ 30.00
Long-Side Service Connection	$ 120.00

(1) Applies only to 1-inch conduit without brackets.

SCHEDULE 300 (Concluded)

SERVICE OF LIMITED DURATION (Rule L)

Standard Temporary Service

Service Connection Required:

No permanent Customer obtained	$530.00	**(I)**
Permanent Customer obtained		
Overhead Service	$355.00	**(N)**
Underground Service	$300.00	**(N)**
Existing service	$140.00	**(I)**

Enhanced Temporary Service

Fixed fee for 12-month period	$275.00	**(I)**

Temporary Area Lights	$400.00 (first luminaire) $345.00 (each additional luminaire) $450.00 (first pole) $400.00 (each additional pole)

SCHEDULE 485
LARGE NONRESIDENTIAL
COST OF SERVICE OPT-OUT
(201 - 1,000 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

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

ENROLLMENT PERIODS

Minimum Five-Year Option

Enrollment Period A: No longer Applicable.

Enrollment Period B: Applicable to any Customer who enrolled between September 1, 2003 and September 30, 2003 with a minimum service period from January 1, 2004 through December 31, 2008.

Enrollment Period C: Applicable to any Customer who enrolled between September 1, 2004 and September 30, 2004, with a minimum service period from January 1, 2005 through December 31, 2009.

Enrollment Period D: Applicable to any customer who enrolled between September 1, 2005 and September 30, 2005, with a minimum service period from January 1, 2006 through December 31, 2010.

Enrollment Period E: Applicable to any customer who enrolled between September 1, 2006 and September 30, 2006, with a minimum service period from January 1, 2007 through December 31, 2011.

Enrollment Period F: Applicable to any customer who enrolled between September 1, 2007 and September 30, 2007, with a minimum service period from January 1, 2008 through December 31, 2012.

Enrollment Period G: Applicable to any customer who enrolled between September 1, 2008 and September 30, 2008, with a minimum service period from January 1, 2009 through December 31, 2013.

SCHEDULE 485 (Continued)

ENROLLMENT PERIODS (Continued)

Minimum Five-Year Option (Continued)

Enrollment Period H: Applicable to any customer who enrolled between September 1, 2009 and September 30, 2009, with a minimum service period from January 1, 2010 through December 31, 2014.

Fixed Three-Year Option

This option was not available during Enrollment Periods A and B.

Enrollment Period C: No longer Applicable.

Enrollment Period D: Applicable to any Customer who enrolled between September 1, 2005 and September 30, 2005, with a service period from January 1, 2006 through December 31, 2008.

Enrollment Period E: Applicable to any Customer who enrolled between September 1, 2006 and September 30, 2006, with a service period from January 1, 2007 through December 31, 2009.

Enrollment Period F: Applicable to any Customer who enrolled between September 1, 2007 and September 30, 2007, with a service period from January 1, 2008 through December 31, 2010.

Enrollment Period G: Applicable to any customer who enrolled between September 1, 2008 and September 30, 2008, with a minimum service period from January 1, 2009 through December 31, 2011.

Enrollment Period H: Applicable to any customer who enrolled between September 1, 2009 and September 30, 2009, with a minimum service period from January 1, 2010 through December 31, 2012.

CHANGE IN APPLICABILITY

If a Customer's usage changes such that they no longer qualify as a Large Nonresidential Customer, they will have their service terminated under this schedule and will move to an otherwise applicable schedule.

SCHEDULE 485 (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
Basic Charge	$400.00	$360.00
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 200 kW	$2.04	$1.97
Over 200 kW	$2.04	$1.97
per kW of monthly On-Peak Demand	$1.95	$1.88
System Usage Charge		
per kWh	0.400 ¢	0.386 ¢

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

MARKET BASED PRICING OPTION

Energy Supply

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

Direct Access Service

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

SCHEDULE 485 (Continued)

MARKET BASED PRICING OPTION (Continued)

Company Supplied Energy

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

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

Wheeling Charge

The Wheeling Charge will be $1.519 per kW of monthly Demand.

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 Facility Capacity and Demand (in kW) will be 200 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	1.0484
Secondary Delivery Voltage	1.0826

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 must give the Company not less than two years notice to terminate service under this schedule. Such notice 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 485 (Concluded)

SPECIAL CONDITIONS (Continued)

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.

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.

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

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.

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.

9. Customers selecting service under this schedule will be limited to a Company/ESS Split Bill.

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 two 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 489
LARGE NONRESIDENTIAL
COST-OF-SERVICE OPT-OUT
(>1000 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

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

ENROLLMENT PERIODS

Minimum Five-Year Option

Enrollment Period A: No longer Applicable.

Enrollment Period B: Applicable to any Customer who enrolled between September 1, 2003 and September 30, 2003 with a minimum service period from January 1, 2004 through December 31, 2008.

Enrollment Period C: Applicable to any Customer who enrolled between September 1, 2004 and September 30, 2004, with a minimum service period from January 1, 2005 through December 31, 2009.

Enrollment Period D: Applicable to any customer who enrolled between September 1, 2005 and September 30, 2005, with a minimum service period from January 1, 2006 through December 31, 2010.

Enrollment Period E: Applicable to any customer who enrolled between September 1, 2006 and September 30, 2006, with a minimum service period from January 1, 2007 through December 31, 2011.

Enrollment Period F: Applicable to any customer who enrolled between September 1, 2007 and September 30, 2007, with a minimum service period from January 1, 2008 through December 31, 2012.

Enrollment Period G: Applicable to any customer who enrolled between September 1, 2008 and September 30, 2008, with a minimum service period from January 1, 2009 through December 31, 2013.

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	$1,310.00	$1,040.00	$2,020.00	**(I)**
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.77	$1.73	$1.73	**(R)(I)(C)**
Over 4,000 kW	$0.38	$0.34	$0.34	**(R) (C)**
per kW of monthly On-Peak Demand	$2.05	$1.98	$0.91	**(I)(R)**
System Usage Charge				
per kWh	0.427 ¢	0.403 ¢	0.389 ¢	**(I)**

* See Schedule 100 for applicable adjustments.

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

MARKET BASED PRICING OPTION

Energy Supply

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

Direct Access Service

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

SCHEDULE 489 (Continued)

MARKET BASED PRICING OPTION (Continued)

Company Supplied Energy

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

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

Wheeling Charge

The Wheeling Charge will be $1.519 per kW of monthly Demand. **(R)**

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 **(C)** 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	1.0337	
Primary Delivery Voltage	1.0484	**(R)**
Secondary Delivery Voltage	1.0826	**(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 must give the Company not less than two years notice to terminate service under this schedule. Such notice 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 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	$ 8.10 (2)	(I)
	400	21,000	147	11.13 (2)	
	1,000	55,000	374	20.27 (2)	
HPS	70	6,300	30	6.56 (2)	
	100	9,500	43	7.08	
	150	16,000	62	7.81	
	200	22,000	79	8.88	
	250	29,000	102	9.75	
	310	37,000	124	11.30 (2)	
	400	50,000	163	12.03	(I)

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

SCHEDULE 515 (Continued)

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

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate[1] Per Luminaire	
Flood , HPS	100	9,500	43	$ 7.47 [2]	(I)
	200	22,000	79	8.97 [2]	
	250	29,000	102	10.10	
	400	50,000	163	12.35	
Shoebox, HPS (bronze color, flat lens, or drop lens, multi-volt)	70	6,300	30	7.37	
	100	9,500	43	8.05	
	150	16,500	62	9.03	
Special Acorn Type, HPS	100	9,500	43	10.95	
HADCO Victorian, HPS	150	16,500	62	11.36	
	200	22,000	79	12.11	
	250	29,000	102	13.04	
Early American Post-Top, HPS, Black	100	9,500	43	8.04	
Special Types					
Cobrahead, Metal Halide	175	12,000	71	8.39	
Flood, Metal Halide	400	40,000	156	12.07	
Flood, HPS	750	105,000	285	19.25	
HADCO Independence, HPS	100	9,500	43	10.30	
	150	16,000	62	11.01	
HADCO Capitol Acorn, HPS	100	9,500	43	14.62	
	150	16,000	62	15.33	
	200	22,000	79	15.95	
	250	29,000	102	16.97	
HADCO Techtra, HPS	100	9,500	43	17.97	
	150	16,000	62	18.68	
	250	29,000	102	26.78	
KIM Archetype, HPS	250	29,000	102	14.38	
	400	50,000	163	16.42	
Holophane Mongoose, HPS	150	16,000	62	10.04	
	250	29,000	102	11.59	
	400	40,000	163	13.86	(I)

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

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	$12.00	**(R)**
Three Phase	$16.00	**(R)**
Distribution Charge		
First 5,000 kWh	3.541 ¢ per kWh	**(I)**
Over 5,000 kWh	0.817 ¢ 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, 2006.

MONTHLY RATE

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

Basic Charge			
Single Phase Service	$20.00		
Three Phase Service	$25.00		
Distribution Charge	5.372	¢ 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**	$30.00	
Winter Months**	No Charge	
Distribution Charge		
First 50 kWh per kW of Demand	3.276 ¢ per kWh	(I)
Over 50 kWh per kW of Demand	1.276 ¢ 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. **(C)**

CHARACTER OF SERVICE

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

MONTHLY RATE

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

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge				
Three Phase Service	$1,310.00	$1,040.00	$2,020.00	**(I)**
Distribution Charge				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.77	$1.73	$1.73	**(R)(I)(C)**
Over 4,000 kW	$0.38	$0.34	$0.34	**(R) (C)**
per kW of monthly On-Peak Demand**	$2.05	$1.98	$0.91	**(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	0.427 ¢	0.403 ¢	0.389 ¢	**(I)**

* 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.

Portland General Electric Company **Fifth Revision of Sheet No. 576R-1**
P.U.C. Oregon No. E-18 **Canceling Fourth Revision of Sheet No. 576R-1**

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	
				(C)
Daily Economic Replacement Power (ERP) Demand Charge				
per kW of Daily ERP Demand during On-Peak hours per day**	$0.080	$0.077	$0.035	(I)(R)
System Usage Charge				
per kWh of ERP	0.427 ¢	0.403 ¢	0.389 ¢	(I)
Transaction Fee				
per Energy Needs Forecast (ENF) submission or revision	$50.00	$50.00	$50.00	(C)

* 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) **(C)**

AVAILABLE

In all territory served by the Company.

APPLICABLE
To each Large Nonresidential Customer whose Demand has not exceeded 200 kW more than once in the proceeding 13 months and who have chosen to receive Electricity from an Electricity Service Supplier (ESS). **(C)**

CHARACTER OF SERVICE

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

MONTHLY RATE

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

(D)

Basic Charge		
Single Phase Service	$20.00	**(I)**
Three Phase Service	$30.00	
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 30 kW	$3.00	**(I)**
Over 30 kW	$2.50	**(I)**
per kW of monthly Demand	$1.83	**(R)**
System Usage Charge		
per kWh	0.380 ¢	**(I)**

(D)

* 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 583 (Continued)

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.

FACILITY CAPACITY

The Facility Capacity shall 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. **(C)**

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 include those summarized in Schedule 100.

NOVEMBER ELECTION WINDOW

Enrollment for 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 Enrollment Windows 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 585
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE
(201 – 1,000 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE
To each Large Nonresidential Customer whose Demand has exceeded 200 kW but not exceeded 1,000 kW more than once in the proceeding 13 months and 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 at the applicable Delivery Voltage per Point of Delivery (POD)*:

	Delivery Voltage	
	Secondary	Primary
Basic Charge	$400.00	$360.00
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 200 kW	$2.04	$1.97
Over 200 kW	$2.04	$1.97
per kW of monthly On-Peak Demand	$1.95	$1.88
System Usage Charge		
per kWh	0.400 ¢	0.386 ¢

* 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 (Continued)

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.

FACILITY CAPACITY

The Facility Capacity shall 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.

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 include those summarized in Schedule 100.

NOVEMBER ELECTION WINDOW

Enrollment for 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 Enrollment Windows 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 585 (Concluded)

SPECIAL CONDITIONS

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

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.

TERM

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

SCHEDULE 589
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE
(>1000 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has exceeded 1,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 1,000 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	$1,310.00	$1,040.00	$2,020.00	**(I)**
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.77	$1.73	$1.73	**(R)(I)(C)**
Over 4,000 kW	$0.38	$0.34	$0.34	**(R) (C)**
per kW of monthly on-peak Demand	$2.05	$1.98	$0.91	**(I) (R)**
System Usage Charge				
per kWh	0.427 ¢	0.403 ¢	0.389 ¢	**(I)**

* See Schedule 100 for applicable adjustments.

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

SCHEDULE 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 luminaire based on the Monthly kWhs applicable to each installed luminaire.

Distribution Charge 3.654 ¢ per kWh **(I)**

Energy Charge Provided by Energy Service Supplier

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Installation Labor Rates [1]	Straight Time	Overtime
	$117.00 per hour	$165.00 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.

SCHEDULE 591 (Continued)

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 **	100	9,500	43	*	$4.13	$1.57	(I)
	150	16,000	62	*	4.84	2.27	
	200	22,000	79	*	5.50	2.89	
	250	29,000	102	*	6.34	3.73	
	400	50,000	163	*	8.58	5.96	
Cobrahead	100	9,500	43	$6.80	4.32	1.57	
	150	16,000	62	7.52	5.03	2.27	
	200	22,000	79	8.55	5.69	2.89	
	250	29,000	102	9.42	6.52	3.73	
	400	50,000	163	11.69	8.79	5.96	
Flood	250	29,000	102	9.73	6.59	3.73	
	400	50,000	163	11.98	8.84	5.96	
Early American Post-Top	100	9,500	43	7.28	4.40	1.57	
Shoebox (Bronze color, flat	70	6,300	30	6.94	3.92	1.10	
Lens, or drop lens, multi-volt)	100	9,500	43	7.68	4.47	1.57	
	150	16,000	62	8.63	5.18	2.27	(I)

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

RATES FOR STANDARD POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B
Fiberglass, Black	20	$4.10	$0.14
Fiberglass, Bronze	30	5.47	0.18
Fiberglass, Gray	30	5.49	0.18
Wood, Standard	30 to 35	4.71	0.15
Wood, Standard	40 to 55	5.91	0.20

SCHEDULE 591 (Continued)

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	$10.31	$4.80	$1.57	(I)
HADCO Independence, HPS	100	9,500	43	9.73	4.81	1.57	
	150	16,000	62	10.44	5.52	2.27	
HADCO Capitol Acorn, HPS	100	9,500	43	13.62	4.91	1.57	
	150	16,000	62	14.33	5.62	2.27	
	200	22,000	79	14.95	6.24	2.89	
	250	29,000	102	15.79	7.08	3.73	
Special Architectural Types							
HADCO Victorian, HPS	150	16,000	62	10.75	5.50	2.27	
	200	22,000	79	11.50	6.21	2.89	
	250	29,000	102	12.42	7.05	3.73	
HADCO Techtra, HPS	100	9,500	43	16.70	5.78	1.57	
	150	16,000	62	17.41	6.49	2.27	
	250	29,000	102	24.89	8.55	3.73	
KIM Archetype, HPS	250	29,000	102	*	7.06	3.73	
	400	50,000	163	*	9.28	5.96	
HADCO Westbrooke, HPS	70	6,300	30	14.10	4.50	1.10	
	100	9,500	43	14.53	4.96	1.57	
	150	16,000	62	15.24	5.67	2.27	
	200	22,000	79	16.00	6.29	2.89	
	250	29,000	102	16.84	7.13	3.73	
Special Types							
Cobrahead, Metal Halide	175	12,000	71	8.09	5.54	2.59	
Flood, Metal Halide	400	40,000	156	11.72	8.70	5.70	
Flood, HPS	750	105,000	285	18.74	14.33	10.41	
Holophane Mongoose, HPS	150	16,000	62	9.54	5.27	2.27	
	250	29,000	102	11.09	6.74	3.73	
	400	50,000	163	13.36	8.99	5.96	(I)

* Not offered.

SCHEDULE 591 (Continued)

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	*	*	$1.43	(I)
	175	7,000	66	$7.79	$5.12	2.41	
	250	10,000	94	9.72	6.35	3.43	
	400	21,000	147	10.82	8.16	5.37	
	1,000	55,000	374	19.90	16.75	13.67	
Special Box Similar to GE "Space-Glo"							
HPS	70	6,300	30	9.81	3.93	1.10	
Mercury Vapor	175	7,000	66	11.26	5.16	2.41	
Special box, Anodized Aluminum							
Similar to GardCo Hub							
HPS	Twin 70	6,300	60	*	*	2.19	
	70	6,300	30	*	*	1.10	
	100	9,500	43	10.07	4.72	1.57	
	150	16,000	62	*	5.43	2.27	
	250	29,000	102	*	*	3.73	
	400	50,000	163	*	*	5.96	
Metal Halide	250	20,500	99	*	6.98	3.62	
	400	40,000	156	*	9.44	5.70	
Cobrahead, Dual Wattage HPS							
70/100 Watt Ballast	100	9,500	43	*	4.30	1.57	
100/150 Watt Ballast	100	9,500	43	*	4.30	1.57	
100/150 Watt Ballast	150	16,000	62	*	5.01	2.27	
Special Architectural Types							(I)
KIM SBC Shoebox, HPS	150	16,000	62	*	5.92	2.27	

* 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	$9.58	$3.93	$1.10	(I)
Special GardCo Bronze Alloy							
HPS	70	5,000	30	*	*	1.10	
Mercury Vapor	175	7,000	66	*	*	2.41	
Special Acrylic Sphere							
Mercury Vapor	400	21,000	147	*	*	5.37	
Early American Post-Top, HPS							
Black	70	6,300	30	6.19	3.83	1.10	
Rectangle Type	200	22,000	79	*	*	2.89	
Incandescent	92	1,000	31	*	*	1.13	
	182	2,500	62	*	*	2.27	
Town and Country Post-Top							
Mercury Vapor	175	7,000	66	7.89	5.11	2.41	
Flood, HPS	70	6,300	30	6.79	3.90	1.10	
	100	9,500	43	7.15	4.34	1.57	
	200	22,000	79	8.87	5.73	2.89	
Cobrahead, HPS							
Non-Power Door	70	6,300	30	6.28	3.89	1.10	
Power Door	310	37,000	124	10.93	7.67	4.53	
Special Types Customer-Owned & Maintained							
Ornamental, HPS	100	9,500	43	*	*	1.57	
Twin ornamental, HPS	Twin 100	9,500	86	*	*	3.14	
Compact Fluorescent	28	N/A	12	*	*	0.44	(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	$5.83	*
Bronze Alloy GardCo	12	*	$0.24
Concrete, Ornamental	35 or less	9.48	0.32
Steel, Painted Regular **	25	9.48	0.32
Steel, Painted Regular **	30	10.26	0.34
Steel, Unpainted 6-foot Mast Arm **	30	*	0.34
Steel, Unpainted 6-foot Davit Arm **	30	*	0.35
Steel, Unpainted 8-foot Mast Arm **	35	*	0.38
Steel, Unpainted 8-foot Davit Arm **	35	*	0.38
Wood, Laminated without Mast Arm	20	5.30	0.14
Wood, Laminated Street Light Only	20	4.10	*
Wood, Curved Laminated	30	6.84	0.25
Wood, Painted Underground	35	4.71	0.20
Wood, Painted Street Light Only	35	4.71	*

* 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	$11.76	$3.22	$1.17	(I)
	165	12,000	60	14.47	4.32	2.19	
HADCO Techtra, QL	85	6,000	32	15.14	3.35	1.17	
	165	12,000	60	16.87	4.41	2.19	(I)

SCHEDULE 592
TRAFFIC SIGNALS
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

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

CHARACTER OF SERVICE

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

MONTHLY RATE

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

Distribution Charge	2.563 ¢ 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 594
COMMUNICATION DEVICES ELECTRICITY SERVICE RIDER
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments that have communication devices with energy requirements not exceeding 25 line watts per unit, that are installed on streetlights and, or traffic signals served under Schedules 91 and, or 92.

CHARACTER OF SERVICE

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

MONTHLY RATE*

The charge per Point of Delivery is:*

Distribution Charge	2.563 ¢ per kWh	**(I)**

* See Schedule 100 for applicable adjustments

The monthly kWh charge for service under this rider will be the number of units times estimated monthly usage determined using the following formula:

[((No. of Units x line watts per unit) x annual operating hours) / 1000] / 12

Where:
1) Annual operating hours are 8760
2) Line watts are based on the electrical data provided in the manufacturer's product specifications using the following criteria:

[(110 nominal volts x rated amps) x percentage of operational rating]

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:	6.20%	2.78%	1.31%	**(R)**

RULE G
DIRECT ACCESS SERVICE AND BILLING

1. Direct Access Service

All Customers, except Residential, may elect to receive Direct Access Service from an ESS under the terms of the parallel Direct Access schedule (500 series). Direct Access Service is also an option for eligible Nonresidential Customers served on Schedules 485 and 489. **(C)**

A. **Enrollment**

Direct Access Service is only available upon acceptance of an Enrollment DASR by the Company. Prerequisites and notification requirements are as contained in each service schedule and Rule K.

B. **Emergency Default Service**

The Company will provide Emergency Default Service under Schedule 81 when an ESS or the Customer informs the Company that the ESS is no longer providing service or when the Company becomes aware that the Customer is no longer receiving service from the ESS and the Company has not received the 10 business day notice required for Standard Service under the appropriate schedule.

2. Special Requirements for Direct Access Billings

A. **Generally**

A Customer purchasing Electricity from an ESS may choose from two billing options: the ESS bills for all services (ESS Consolidated Bill) or the Company and the ESS each bill for their respective services (Company/ESS Split Bill).

1) **Company/ESS Split Bill**

When the Customer is receiving a Company/ESS Split Bill, the Company may disconnect Electricity Service for nonpayment of Direct Access Service under the guidelines set forth in Rule H.

2) **ESS Consolidated Bill**

When the Customer receives an ESS Consolidated Bill, failure of the Customer to pay the ESS for Direct Access Service does not relieve the ESS of the responsibility to pay the Company for Direct Access Services and any other Company charges.

TABLE 1
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS
2011 COS ONLY

		Forecast SDEC09E11		TOTAL ELECTRIC BILLS			
				CURRENT	PROPOSED	Change	
CATEGORY	**RATE SCHEDULE**	CUSTOMERS	MWH SALES	w/ Sch. 111, 121, 122, 125, 141, 145	w/ Sch. 111, 121, 122, 125, 141, 145	AMOUNT	PCT.
Residential	7	723,631	7,623,626	$814,982,044	$887,004,110	$72,022,066	8.8%
Employee Discount				($923,060)	($1,026,174)	($103,114)	
Subtotal				$814,058,984	$885,977,936	$71,918,952	8.8%
Outdoor Area Lighting	15	0	24,166	$4,514,922	$4,605,055	$90,132	2.0%
General Service <30 kW	32	85,966	1,466,414	$147,875,124	$160,044,443	$12,169,319	8.2%
Opt. Time-of-Day G.S. >30 kW	38	362	38,502	$4,045,821	$4,646,771	$600,951	14.9%
Irrig. & Drain. Pump. < 30 kW	47	3,166	22,186	$2,630,180	$3,020,657	$390,478	14.8%
Irrig. & Drain. Pump. > 30 kW	49	1,336	69,403	$5,811,209	$6,723,162	$911,952	15.7%
General Service 31-200 kW	83-S	11,027	2,422,868	$195,372,085	$213,481,095	$18,109,010	9.3%
General Service 201-1,000 kW							
Secondary	85-S	1,870	2,691,790	$209,694,885	$221,744,597	$12,049,712	5.7%
Primary	85-P	130	263,099	$19,304,616	$20,445,781	$1,141,166	5.9%
Schedule 89 > 1 MW							
Secondary	89-S	110	658,051	$49,549,476	$51,566,231	$2,016,755	4.1%
Primary	89-P	109	2,634,362	$177,302,646	$180,353,415	$3,050,770	1.7%
Subtransmission	89-T	8	500,739	$31,817,775	$32,511,554	$693,779	2.2%
Street & Highway Lighting	91	207	108,918	$18,124,060	$18,482,486	$358,426	2.0%
Traffic Signals	92	17	4,740	$391,666	$399,345	$7,679	2.0%
Recreational Field Lighting	93	23	573	$94,439	$108,460	$14,021	14.8%
TOTAL (CYCLE YEAR BASIS)		827,961	18,529,435	$1,680,587,889	$1,804,110,990	$123,523,101	7.3%
============================							
CONVERSION ADJUSTMENT				$725,687	$779,025		
===================================							
TOTAL (CALENDAR YEAR BASIS)			18,537,436	**$1,681,313,576**	**$1,804,890,014**	**$123,576,439**	7.3%

TABLE 2
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS
2011 COS ONLY

		Forecast SDEC09E11		TOTAL ELECTRIC BILLS			
				CURRENT	PROPOSED	Change	
CATEGORY	**RATE SCHEDULE**	CUSTOMERS	MWH SALES	w/ Sch. 111, 121, 122, 125, Sch 102	w/ Sch. 111, 121, 122, 125, Sch 102	AMOUNT	PCT.
Residential	7	723,631	7,623,626	$767,334,382	$839,356,448	$72,022,066	9.4%
Employee Discount				($868,331)	($971,445)	($103,114)	
Subtotal				$766,466,051	$838,385,003	$71,918,952	9.4%
Outdoor Area Lighting	15	0	24,166	$4,470,260	$4,560,392	$90,132	2.0%
General Service <30 kW	32	85,966	1,466,414	$146,501,476	$158,670,795	$12,169,319	8.3%
Opt. Time-of-Day G.S. >30 kW	38	362	38,502	$4,039,999	$4,640,949	$600,951	14.9%
Irrig. & Drain. Pump. < 30 kW	47	3,166	22,186	$2,503,133	$2,893,610	$390,478	15.6%
Irrig. & Drain. Pump. > 30 kW	49	1,336	69,403	$5,436,805	$6,348,757	$911,952	16.8%
General Service 31-200 kW	83-S	11,027	2,422,868	$194,175,277	$212,284,287	$18,109,010	9.3%
General Service 201-1,000 kW							
Secondary	85-S	1,870	2,691,790	$209,146,738	$221,196,451	$12,049,712	5.8%
Primary	85-P	130	263,099	$19,253,215	$20,394,380	$1,141,166	5.9%
Schedule 89 > 1 MW							
Secondary	89-S	110	658,051	$49,518,881	$51,535,636	$2,016,755	4.1%
Primary	89-P	109	2,634,362	$177,302,646	$180,353,415	$3,050,770	1.7%
Subtransmission	89-T	8	500,739	$31,817,775	$32,511,554	$693,779	2.2%
Street & Highway Lighting	91	207	108,918	$18,124,060	$18,482,486	$358,426	2.0%
Traffic Signals	92	17	4,740	$391,666	$399,345	$7,679	2.0%
Recreational Field Lighting	93	23	573	$94,439	$108,460	$14,021	14.8%
TOTAL (CYCLE YEAR BASIS)		827,961	18,529,435	$1,629,242,421	$1,752,765,522	$123,523,101	7.6%
============================							
CONVERSION ADJUSTMENT				$703,516	$756,853		
====================================							
TOTAL (CALENDAR YEAR BASIS)			18,537,436	**$1,629,945,937**	**$1,753,522,375**	**$123,576,439**	7.6%

TABLE 3
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS
2011 COS ONLY

CATEGORY	RATE SCHEDULE	Forecast SDEC09E11 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	723,631	7,623,626	$764,437,404	$836,993,124	$72,555,720	9.5%
Employee Discount				($865,003)	($968,730)	($103,727)	
Subtotal				$763,572,401	$836,024,394	$72,451,993	9.5%
Outdoor Area Lighting	15	0	24,166	$4,461,799	$4,553,623	$91,824	2.1%
General Service <30 kW	32	85,966	1,466,414	$145,944,232	$158,216,200	$12,271,968	8.4%
Opt. Time-of-Day G.S. >30 kW	38	362	38,502	$4,028,354	$4,628,535	$600,181	14.9%
Irrig. & Drain. Pump. < 30 kW	47	3,166	22,186	$2,494,702	$2,886,733	$392,031	15.7%
Irrig. & Drain. Pump. > 30 kW	49	1,336	69,403	$5,415,981	$6,326,545	$910,564	16.8%
General Service 31-200 kW	83-S	11,027	2,422,868	$193,470,809	$211,531,361	$18,060,553	9.3%
General Service 201-1,000 kW							
Secondary	85-S	1,870	2,691,790	$208,366,119	$220,361,996	$11,995,877	5.8%
Primary	85-P	130	263,099	$19,176,750	$20,312,653	$1,135,904	5.9%
Schedule 89 > 1 MW							
Secondary	89-S	110	658,051	$49,317,594	$51,321,187	$2,003,593	4.1%
Primary	89-P	109	2,634,362	$176,465,590	$179,463,672	$2,998,082	1.7%
Subtransmission	89-T	8	500,739	$31,657,539	$32,341,303	$683,765	2.2%
Street & Highway Lighting	91	207	108,918	$18,094,652	$18,450,900	$356,247	2.0%
Traffic Signals	92	17	4,740	$390,244	$397,828	$7,584	1.9%
Recreational Field Lighting	93	23	573	$94,284	$108,294	$14,009	14.9%
TOTAL (CYCLE YEAR BASIS)		827,961	18,529,435	$1,622,951,049	$1,746,925,224	$123,974,174	7.6%
============================							
CONVERSION ADJUSTMENT				$700,799	$754,332		
====================================							
TOTAL (CALENDAR YEAR BASIS)			18,537,436	**$1,623,651,848**	**$1,747,679,555**	**$124,027,707**	7.6%

TABLE 4
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS
2011 COS ONLY

CATEGORY	RATE SCHEDULE	CUSTOMERS (Forecast SDEC09E11)	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	723,631	7,623,626	$775,644,134	$848,199,854	$72,555,720	9.4%
Employee Discount				($865,003)	($968,730)	($103,727)	
Subtotal				$774,779,131	$847,231,124	$72,451,993	9.4%
Outdoor Area Lighting	15	0	24,166	$4,523,552	$4,615,376	$91,824	2.0%
General Service <30 kW	32	85,966	1,466,414	$147,967,541	$160,239,509	$12,271,968	8.3%
Opt. Time-of-Day G.S. >30 kW	38	362	38,502	$4,061,012	$4,661,193	$600,181	14.8%
Irrig. & Drain. Pump. < 30 kW	47	3,166	22,186	$2,530,422	$2,922,452	$392,031	15.5%
Irrig. & Drain. Pump. > 30 kW	49	1,336	69,403	$5,495,596	$6,406,160	$910,564	16.6%
General Service 31-200 kW	83-S	11,027	2,422,868	$196,163,096	$214,223,649	$18,060,553	9.2%
General Service 201-1,000 kW							
Secondary	85-S	1,870	2,691,790	$211,434,759	$223,430,636	$11,995,877	5.7%
Primary	85-P	130	263,099	$19,470,348	$20,606,252	$1,135,904	5.8%
Schedule 89 > 1 MW							
Secondary	89-S	110	658,051	$49,782,038	$51,785,631	$2,003,593	4.0%
Primary	89-P	109	2,634,362	$176,762,602	$179,760,684	$2,998,082	1.7%
Subtransmission	89-T	8	500,739	$31,657,539	$32,341,303	$683,765	2.2%
Street & Highway Lighting	91	207	108,918	$18,342,985	$18,699,233	$356,247	1.9%
Traffic Signals	92	17	4,740	$395,695	$403,279	$7,584	1.9%
Recreational Field Lighting	93	23	573	$95,561	$109,571	$14,009	14.7%
TOTAL (CYCLE YEAR BASIS)		827,961	18,529,435	$1,643,461,879	$1,767,436,053	$123,974,174	7.5%
============================							
CONVERSION ADJUSTMENT				$709,656	$763,188		
====================================							
TOTAL (CALENDAR YEAR BASIS)			18,537,436	**$1,644,171,534**	**$1,768,199,241**	**$124,027,707**	7.5%

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	$14.79	$15.42	4.3%
100	$18.78	$20.04	6.7%
200	$26.78	$29.30	9.4%
250	$30.78	$33.93	10.2%
300	$35.67	$38.55	8.1%
400	$45.48	$47.79	5.1%
500	$55.34	$57.06	3.1%
600	$65.14	$68.08	4.5%
700	$74.95	$79.13	5.6%
800	$84.75	$90.17	6.4%
900	$94.57	$101.22	7.0%
1,000	$104.38	$112.26	7.5%
1,100	$114.19	$124.08	8.7%
1,200	$124.02	$135.91	9.6%
1,300	$133.83	$147.73	10.4%
1,400	$143.64	$159.55	11.1%
1,500	$153.49	$171.39	11.7%
1,600	$163.29	$183.20	12.2%
1,700	$173.10	$195.02	12.7%
1,800	$182.91	$206.84	13.1%
2,000	$202.54	$230.49	13.8%
2,300	$231.98	$265.96	14.6%
2,750	$276.15	$319.15	15.6%
3,000	$300.70	$348.72	16.0%
3,500	$349.80	$407.85	16.6%
4,000	$398.85	$466.95	17.1%
4,500	$447.96	$526.09	17.4%
5,000	$497.01	$585.19	17.7%
7,500	$742.43	$880.78	18.6%
10,000	$987.79	$1,176.34	19.1%

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	$61.43	$65.97	7.4%	$58.21	$62.75	7.8%
600	$71.23	$76.68	7.7%	$67.37	$72.82	8.1%
700	$81.04	$87.41	7.9%	$76.53	$82.90	8.3%
800	$90.81	$98.11	8.0%	$85.66	$92.96	8.5%
900	$100.64	$108.83	8.1%	$94.84	$103.03	8.6%
1,000	$110.44	$119.56	8.3%	$104.00	$113.12	8.8%
1,500	$159.51	$173.17	8.6%	$149.85	$163.51	9.1%
1,750	$184.00	$199.96	8.7%	$172.74	$188.69	9.2%
2,000	$208.52	$226.76	8.7%	$195.65	$213.88	9.3%
2,500	$257.60	$280.37	8.8%	$241.50	$264.27	9.4%
3,500	$355.68	$387.57	9.0%	$333.14	$365.03	9.6%
4,000	$404.69	$441.15	9.0%	$378.94	$415.40	9.6%
4,500	$453.76	$494.76	9.0%	$424.79	$465.79	9.7%
5,000	$502.77	$548.35	9.1%	$470.58	$516.16	9.7%
6,000	$578.47	$627.49	8.5%	$539.85	$588.86	9.1%
7,000	$654.17	$706.63	8.0%	$609.11	$661.57	8.6%
8,000	$729.87	$785.77	7.7%	$678.37	$734.27	8.2%
9,000	$805.57	$864.91	7.4%	$747.63	$806.97	7.9%
10,000	$881.27	$944.05	7.1%	$816.90	$879.67	7.7%
14,000	$1,184.07	$1,260.61	6.5%	$1,093.95	$1,170.49	7.0%
15,000	$1,259.77	$1,339.75	6.3%	$1,163.21	$1,243.19	6.9%
20,000	$1,638.27	$1,735.45	5.9%	$1,509.52	$1,606.70	6.4%
21,900	$1,782.11	$1,885.81	5.8%	$1,641.12	$1,744.82	6.3%

PORTLAND GENERAL ELECTRIC
Effect of proposed rate change on Monthly Bills
Tariff Schedule 32, 3-phase Service

	Net Monthly Bill (without RPA credit)			Net Monthly Bill (with RPA credit)		
kWh	Current Prices	Proposed Prices	Percent Difference	Current Prices	Proposed Prices	Percent Difference
500	$65.55	$70.09	6.9%	$62.33	$66.87	7.3%
600	$75.35	$80.80	7.2%	$71.49	$76.94	7.6%
700	$85.16	$91.53	7.5%	$80.65	$87.02	7.9%
800	$94.93	$102.23	7.7%	$89.78	$97.08	8.1%
900	$104.76	$112.95	7.8%	$98.96	$107.15	8.3%
1,000	$114.56	$123.68	8.0%	$108.12	$117.24	8.4%
1,500	$163.63	$177.29	8.3%	$153.97	$167.63	8.9%
1,750	$188.12	$204.08	8.5%	$176.86	$192.81	9.0%
2,000	$212.64	$230.88	8.6%	$199.77	$218.00	9.1%
2,500	$261.72	$284.49	8.7%	$245.62	$268.39	9.3%
3,500	$359.80	$391.69	8.9%	$337.26	$369.15	9.5%
4,000	$408.81	$445.27	8.9%	$383.06	$419.52	9.5%
4,500	$457.88	$498.88	9.0%	$428.91	$469.91	9.6%
5,000	$506.89	$552.47	9.0%	$474.70	$520.28	9.6%
6,000	$582.59	$631.61	8.4%	$543.97	$592.98	9.0%
7,000	$658.29	$710.75	8.0%	$613.23	$665.69	8.6%
8,000	$733.99	$789.89	7.6%	$682.49	$738.39	8.2%
9,000	$809.69	$869.03	7.3%	$751.75	$811.09	7.9%
10,000	$885.39	$948.17	7.1%	$821.02	$883.79	7.6%
14,000	$1,188.19	$1,264.73	6.4%	$1,098.07	$1,174.61	7.0%
15,000	$1,263.89	$1,343.87	6.3%	$1,167.33	$1,247.31	6.9%
20,000	$1,642.39	$1,739.57	5.9%	$1,513.64	$1,610.82	6.4%
21,900	$1,786.23	$1,889.93	5.8%	$1,645.24	$1,748.94	6.3%

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	$31.56	$32.44	2.8%	$31.24	$32.12	2.8%
10	100	$37.31	$39.13	4.9%	$36.66	$38.48	5.0%
10	500	$83.61	$92.65	10.8%	$80.39	$89.42	11.2%
10	1,000	$131.15	$149.22	13.8%	$124.71	$142.79	14.5%
10	2,000	$226.24	$262.40	16.0%	$213.36	$249.52	16.9%
10	5,000	$511.50	$601.92	17.7%	$479.31	$569.74	18.9%
20	100	$37.31	$39.13	4.9%	$36.66	$38.48	5.0%
20	200	$48.89	$52.51	7.4%	$47.60	$51.22	7.6%
20	500	$83.61	$92.65	10.8%	$80.39	$89.42	11.2%
20	1,000	$141.44	$159.51	12.8%	$135.00	$153.08	13.4%
20	2,000	$236.53	$272.69	15.3%	$223.65	$259.81	16.2%
20	5,000	$521.79	$612.21	17.3%	$489.60	$580.03	18.5%
20	8,000	$807.05	$951.74	17.9%	$755.55	$900.24	19.2%
30	150	$43.13	$45.82	6.2%	$42.16	$44.85	6.4%
30	500	$83.61	$92.65	10.8%	$80.39	$89.42	11.2%
30	1,000	$141.44	$159.51	12.8%	$135.00	$153.08	13.4%
30	3,000	$341.92	$396.16	15.9%	$322.61	$376.85	16.8%
30	5,000	$532.10	$622.51	17.0%	$499.91	$590.33	18.1%
30	8,000	$817.37	$962.04	17.7%	$765.87	$910.54	18.9%
30	10,000	$1,007.54	$1,188.39	17.9%	$943.17	$1,124.01	19.2%
30	15,000	$1,482.98	$1,754.26	18.3%	$1,386.42	$1,657.70	19.6%

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	$466.13	$534.61	14.7%	$433.23	$501.71	15.8%
40%	35	10,220	$865.28	$1,002.26	15.8%	$799.48	$936.46	17.1%
60%	35	15,330	$1,264.51	$1,469.93	16.2%	$1,165.83	$1,371.24	17.6%
80%	35	20,440	$1,663.67	$1,937.57	16.5%	$1,532.09	$1,805.99	17.9%
20%	50	7,300	$652.66	$750.49	15.0%	$605.66	$703.49	16.2%
40%	50	14,600	$1,222.92	$1,418.56	16.0%	$1,128.93	$1,324.57	17.3%
60%	50	21,900	$1,793.18	$2,086.64	16.4%	$1,652.19	$1,945.66	17.8%
80%	50	29,200	$2,363.42	$2,754.70	16.6%	$2,175.45	$2,566.73	18.0%
20%	70	10,220	$901.34	$1,038.31	15.2%	$835.55	$972.51	16.4%
40%	70	20,440	$1,699.72	$1,973.62	16.1%	$1,568.14	$1,842.04	17.5%
60%	70	30,660	$2,498.08	$2,908.93	16.4%	$2,300.70	$2,711.55	17.9%
80%	70	40,880	$3,296.45	$3,844.24	16.6%	$3,033.28	$3,581.08	18.1%
20%	100	14,600	$1,274.42	$1,470.05	15.4%	$1,180.43	$1,376.06	16.6%
40%	100	29,200	$2,414.92	$2,806.20	16.2%	$2,226.95	$2,618.23	17.6%
60%	100	43,800	$3,555.43	$4,142.38	16.5%	$3,273.47	$3,860.41	17.9%
80%	100	58,400	$4,695.94	$5,478.53	16.7%	$4,319.99	$5,102.58	18.1%
20%	200	29,200	$2,517.92	$2,909.20	15.5%	$2,329.95	$2,721.23	16.8%
40%	200	58,400	$4,798.94	$5,581.53	16.3%	$4,422.99	$5,205.58	17.7%
60%	200	87,600	$7,079.97	$8,253.82	16.6%	$6,516.05	$7,689.90	18.0%
80%	200	116,800	$9,360.99	$10,926.15	16.7%	$8,609.09	$10,174.25	18.2%

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	$132.27	$148.22	12.1%	$125.83	$141.78	12.7%
3,000	$345.32	$393.15	13.9%	$326.00	$373.84	14.7%
5,000	$558.36	$638.08	14.3%	$526.17	$605.89	15.2%
7,000	$771.41	$883.01	14.5%	$726.35	$837.95	15.4%
10,000	$1,090.97	$1,250.40	14.6%	$1,026.59	$1,186.03	15.5%
13,000	$1,410.54	$1,617.79	14.7%	$1,326.85	$1,534.10	15.6%
14,000	$1,517.05	$1,740.26	14.7%	$1,426.93	$1,650.14	15.6%
16,000	$1,730.10	$1,985.19	14.7%	$1,627.10	$1,882.19	15.7%
21,000	$2,262.71	$2,597.52	14.8%	$2,127.52	$2,462.34	15.7%
25,000	$2,688.80	$3,087.38	14.8%	$2,527.87	$2,926.45	15.8%
30,000	$3,221.41	$3,699.70	14.8%	$3,028.29	$3,506.58	15.8%
35,000	$3,754.02	$4,312.04	14.9%	$3,528.71	$4,086.72	15.8%
40,000	$4,286.63	$4,924.36	14.9%	$4,029.13	$4,666.86	15.8%
45,000	$4,819.24	$5,536.68	14.9%	$4,529.55	$5,246.99	15.8%
50,000	$5,351.86	$6,149.01	14.9%	$5,029.98	$5,827.13	15.8%
75,000	$8,014.89	$9,210.64	14.9%	$7,532.08	$8,727.83	15.9%
100,000	$10,677.95	$12,272.27	14.9%	$10,034.20	$11,628.52	15.9%
150,000	$16,004.06	$18,395.52	14.9%	$15,038.43	$17,429.90	15.9%
200,000	$21,330.15	$24,518.78	14.9%	$20,042.65	$23,231.28	15.9%
300,000	$31,982.35	$36,765.30	15.0%	$30,051.10	$34,834.05	15.9%
400,000	$42,634.54	$49,011.81	15.0%	$40,059.54	$46,436.81	15.9%
500,000	$53,286.74	$61,258.33	15.0%	$50,067.99	$58,039.58	15.9%
750,000	$78,806.57	$90,763.94	15.2%	$73,978.45	$85,935.81	16.2%
1,000,000	$105,066.84	$121,010.00	15.2%	$98,629.34	$114,572.50	16.2%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 83, Secondary, 3 phase service

			Net Monthly Billing (without RPA credit)			Net Monthly Bill (with RPA credit)		
Load Factor	kW	kWh	Current Prices	Proposed Prices	Percent Difference	Current Prices	Proposed Prices	Percent Difference
30%	30	6,570	$597.06	$675.72	13.2%	$554.76	$633.43	14.2%
30%	50	10,950	$991.70	$1,095.28	10.4%	$921.21	$1,024.79	11.2%
30%	75	16,425	$1,485.04	$1,619.74	9.1%	$1,379.30	$1,514.00	9.8%
30%	100	21,900	$1,978.38	$2,144.21	8.4%	$1,837.39	$2,003.22	9.0%
30%	135	29,565	$2,669.03	$2,878.45	7.8%	$2,478.70	$2,688.12	8.4%
30%	175	38,325	$3,458.36	$3,717.59	7.5%	$3,211.64	$3,470.87	8.1%
30%	200	43,800	$3,951.68	$4,242.04	7.3%	$3,669.71	$3,960.08	7.9%
50%	30	10,950	$892.41	$987.95	10.7%	$821.92	$917.46	11.6%
50%	50	18,250	$1,484.00	$1,615.69	8.9%	$1,366.52	$1,498.21	9.6%
50%	75	27,375	$2,223.45	$2,400.36	8.0%	$2,047.23	$2,224.13	8.6%
50%	100	36,500	$2,962.96	$3,185.02	7.5%	$2,727.98	$2,950.05	8.1%
50%	135	49,275	$3,998.20	$4,283.56	7.1%	$3,680.99	$3,966.35	7.8%
50%	175	63,875	$5,181.36	$5,539.02	6.9%	$4,770.17	$5,127.82	7.5%
50%	200	73,000	$5,920.82	$6,323.68	6.8%	$5,450.89	$5,853.74	7.4%
70%	30	15,330	$1,187.80	$1,300.20	9.5%	$1,089.12	$1,201.51	10.3%
70%	50	25,550	$1,976.29	$2,136.10	8.1%	$1,811.81	$1,971.62	8.8%
70%	75	38,325	$2,961.90	$3,180.96	7.4%	$2,715.18	$2,934.24	8.1%
70%	100	51,100	$3,947.51	$4,225.82	7.1%	$3,618.54	$3,896.86	7.7%
70%	135	68,985	$5,327.38	$5,688.64	6.8%	$4,883.29	$5,244.55	7.4%
70%	175	89,425	$6,904.36	$7,360.44	6.6%	$6,328.68	$6,784.76	7.2%
70%	200	102,200	$7,889.97	$8,405.31	6.5%	$7,232.06	$7,747.40	7.1%
90%	30	19,710	$1,483.16	$1,612.44	8.7%	$1,356.27	$1,485.56	9.5%
90%	50	32,850	$2,468.57	$2,656.50	7.6%	$2,257.10	$2,445.04	8.3%
90%	75	49,275	$3,700.32	$3,961.58	7.1%	$3,383.11	$3,644.37	7.7%
90%	100	65,700	$4,932.08	$5,266.64	6.8%	$4,509.14	$4,843.69	7.4%
90%	135	88,695	$6,656.53	$7,093.74	6.6%	$6,085.56	$6,522.77	7.2%
90%	175	114,975	$8,627.36	$9,181.87	6.4%	$7,887.21	$8,441.72	7.0%
90%	200	131,400	$9,859.10	$10,486.93	6.4%	$9,013.21	$9,641.04	7.0%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 85, Secondary, 3 phase service
Bill Comparison assumes 63% on-peak, 37% off-peak energy consumption

Load Factor	kW	kWh	Net Monthly Bill: Current Prices	Net Monthly Bill: Proposed Prices	Percent Difference
30%	200	43,800	$3,951.68	$4,406.72	11.5%
30%	300	65,700	$5,925.00	$6,404.09	8.1%
30%	500	109,500	$9,871.65	$10,398.82	5.3%
30%	700	153,300	$13,818.27	$14,393.55	4.2%
30%	800	175,200	$15,791.59	$16,390.92	3.8%
30%	900	197,100	$17,764.90	$18,388.27	3.5%
30%	1,000	219,000	$19,738.22	$20,385.64	3.3%
50%	200	73,000	$5,920.82	$6,401.07	8.1%
50%	300	109,500	$8,878.73	$9,395.60	5.8%
50%	500	182,500	$14,794.51	$15,384.67	4.0%
50%	700	255,500	$20,710.29	$21,373.73	3.2%
50%	800	292,000	$23,668.16	$24,368.25	3.0%
50%	900	328,500	$26,626.07	$27,362.79	2.8%
50%	1,000	365,000	$29,583.93	$30,357.32	2.6%
70%	200	102,200	$7,889.97	$8,395.40	6.4%
70%	300	153,300	$11,832.43	$12,387.11	4.7%
70%	500	255,500	$19,717.37	$20,370.51	3.3%
70%	700	357,700	$27,602.27	$28,353.91	2.7%
70%	800	408,800	$31,544.72	$32,345.60	2.5%
70%	900	459,900	$35,487.20	$36,337.31	2.4%
70%	1,000	511,000	$39,429.65	$40,329.00	2.3%
90%	200	131,400	$9,859.10	$10,389.73	5.4%
90%	300	197,100	$14,786.14	$15,378.61	4.0%
90%	500	328,500	$24,640.23	$25,356.35	2.9%
90%	700	459,900	$34,494.28	$35,334.09	2.4%
90%	800	525,600	$39,421.31	$40,322.96	2.3%
90%	900	591,300	$44,348.33	$45,311.83	2.2%
90%	1,000	657,000	$49,275.36	$50,300.69	2.1%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 85, Primary, 3 phase service
Bill Comparison assumes 63% on-peak, 37% off-peak energy consumption

			Net Monthly Bill		
Load Factor	kW	kWh	Current Prices	Proposed Prices	Percent Difference
30%	200	43,800	$3,791.23	$4,237.57	11.8%
30%	300	65,700	$5,645.68	$6,170.96	9.3%
30%	500	109,500	$9,354.55	$10,037.74	7.3%
30%	700	153,300	$13,063.39	$13,904.50	6.4%
30%	800	175,200	$14,917.83	$15,837.88	6.2%
30%	900	197,100	$16,772.23	$17,771.28	6.0%
30%	1,000	219,000	$18,626.66	$19,704.66	5.8%
50%	200	73,000	$5,696.63	$6,169.96	8.3%
50%	300	109,500	$8,503.77	$9,069.54	6.7%
50%	500	182,500	$14,118.01	$14,868.68	5.3%
50%	700	255,500	$19,732.24	$20,667.84	4.7%
50%	800	292,000	$22,539.34	$23,567.41	4.6%
50%	900	328,500	$25,346.48	$26,466.99	4.4%
50%	1,000	365,000	$28,153.57	$29,366.56	4.3%
70%	200	102,200	$7,602.04	$8,102.34	6.6%
70%	300	153,300	$11,361.83	$11,968.10	5.3%
70%	500	255,500	$18,881.46	$19,699.64	4.3%
70%	700	357,700	$26,401.06	$27,431.17	3.9%
70%	800	408,800	$30,160.84	$31,296.93	3.8%
70%	900	459,900	$33,920.69	$35,162.70	3.7%
70%	1,000	511,000	$37,680.48	$39,028.47	3.6%
90%	200	131,400	$9,507.39	$10,034.71	5.5%
90%	300	197,100	$14,219.89	$14,866.68	4.5%
90%	500	328,500	$23,644.92	$24,530.59	3.7%
90%	700	459,900	$33,069.91	$34,194.50	3.4%
90%	800	525,600	$37,782.40	$39,026.46	3.3%
90%	900	591,300	$42,494.90	$43,858.42	3.2%
90%	1,000	657,000	$47,207.39	$48,690.37	3.1%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 89, Secondary
Bill Comparison assumes 60% on-peak, 40% off-peak energy consumption

			Net Monthly Bill		
Load Factor	kW	kWh	Current Prices	Proposed Prices	Percent Difference
30%	1,000	219,000	$19,476.50	$20,611.06	5.5%
30%	2,000	438,000	$37,428.59	$39,872.82	6.5%
30%	4,000	876,000	$72,438.74	$77,502.29	7.0%
30%	7,500	1,642,500	$134,167.56	$138,803.97	3.5%
30%	10,000	2,190,000	$178,215.25	$182,546.59	2.4%
30%	15,000	3,285,000	$266,310.68	$270,031.83	1.4%
30%	20,000	4,380,000	$354,406.10	$357,517.08	0.9%
50%	1,000	365,000	$29,192.29	$30,224.90	3.5%
50%	2,000	730,000	$56,860.19	$59,100.50	3.9%
50%	4,000	1,460,000	$110,475.90	$115,131.63	4.2%
50%	7,500	2,737,500	$205,370.99	$209,242.71	1.9%
50%	10,000	3,650,000	$273,153.15	$276,464.91	1.2%
50%	15,000	5,475,000	$408,717.53	$410,909.32	0.5%
50%	20,000	7,300,000	$544,281.91	$545,353.73	0.2%
70%	1,000	511,000	$38,908.09	$39,838.74	2.4%
70%	2,000	1,022,000	$75,237.74	$77,274.13	2.7%
70%	4,000	2,044,000	$148,451.06	$152,698.96	2.9%
70%	7,500	3,832,500	$276,574.41	$279,681.46	1.1%
70%	10,000	5,110,000	$368,091.06	$370,383.24	0.6%
70%	15,000	7,665,000	$551,124.38	$551,786.81	0.1%
70%	20,000	10,220,000	$734,157.71	$733,190.38	-0.1%
90%	1,000	657,000	$48,623.90	$49,452.58	1.7%
90%	2,000	1,314,000	$94,225.31	$96,057.80	1.9%
90%	4,000	2,628,000	$186,426.22	$190,266.28	2.1%
90%	7,500	4,927,500	$347,777.84	$350,120.20	0.7%
90%	10,000	6,570,000	$463,028.96	$464,301.56	0.3%
90%	15,000	9,855,000	$693,531.24	$692,664.30	-0.1%
90%	20,000	13,140,000	$924,033.51	$921,027.03	-0.3%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 89, Primary, 3 phase service
Bill Comparison assumes 60% on-peak, 40% off-peak energy consumption

Load Factor	kW	kWh	Net Monthly Bill: Current Prices	Net Monthly Bill: Proposed Prices	Percent Difference
30%	1,000	219,000	$18,796.04	$19,710.55	4.9%
30%	2,000	438,000	$35,995.59	$38,349.90	6.5%
30%	4,000	876,000	$69,500.63	$74,734.57	7.5%
30%	7,500	1,642,500	$128,595.50	$133,857.81	4.1%
30%	10,000	2,190,000	$170,761.82	$176,044.40	3.1%
30%	15,000	3,285,000	$255,094.48	$260,417.61	2.1%
30%	20,000	4,380,000	$339,427.14	$344,790.81	1.6%
50%	1,000	365,000	$28,168.07	$29,005.59	3.0%
50%	2,000	730,000	$54,739.65	$56,939.97	4.0%
50%	4,000	1,460,000	$106,162.71	$111,088.67	4.6%
50%	7,500	2,737,500	$197,220.66	$201,905.51	2.4%
50%	10,000	3,650,000	$262,262.04	$266,774.67	1.7%
50%	15,000	5,475,000	$392,344.81	$396,513.01	1.1%
50%	20,000	7,300,000	$522,427.57	$526,251.35	0.7%
70%	1,000	511,000	$37,540.11	$38,300.63	2.0%
70%	2,000	1,022,000	$72,429.65	$74,475.99	2.8%
70%	4,000	2,044,000	$142,762.80	$147,380.77	3.2%
70%	7,500	3,832,500	$265,845.82	$269,953.21	1.5%
70%	10,000	5,110,000	$353,762.25	$357,504.94	1.1%
70%	15,000	7,665,000	$529,595.13	$532,608.41	0.6%
70%	20,000	10,220,000	$705,428.00	$707,711.88	0.3%
90%	1,000	657,000	$46,912.13	$47,595.66	1.5%
90%	2,000	1,314,000	$90,729.69	$92,622.04	2.1%
90%	4,000	2,628,000	$179,362.89	$183,672.88	2.4%
90%	7,500	4,927,500	$334,470.98	$338,000.91	1.1%
90%	10,000	6,570,000	$445,262.47	$448,235.21	0.7%
90%	15,000	9,855,000	$666,845.45	$668,703.82	0.3%
90%	20,000	13,140,000	$888,428.43	$889,172.42	0.1%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 89, Transmission
Bill Comparison assumes 60% on-peak, 40% off-peak energy consumption

Load Factor	kW	kWh	Net Monthly Bill: Current Prices	Net Monthly Bill: Proposed Prices	Percent Difference
30%	4,000	876,000	$64,704.59	$70,428.17	8.8%
30%	5,000	1,095,000	$80,233.27	$86,035.87	7.2%
30%	10,000	2,190,000	$157,566.64	$163,764.33	3.9%
30%	20,000	4,380,000	$312,233.37	$319,221.26	2.2%
30%	40,000	8,760,000	$621,566.85	$630,135.13	1.4%
30%	50,000	10,950,000	$776,233.58	$785,592.06	1.2%
30%	70,000	15,330,000	$1,085,567.05	$1,096,505.92	1.0%
50%	4,000	1,460,000	$100,407.86	$106,204.82	5.8%
50%	5,000	1,825,000	$124,784.85	$130,679.18	4.7%
50%	10,000	3,650,000	$246,669.79	$253,050.95	2.6%
50%	20,000	7,300,000	$490,439.69	$497,794.51	1.5%
50%	40,000	14,600,000	$977,979.48	$987,281.61	1.0%
50%	50,000	18,250,000	$1,221,749.37	$1,232,025.17	0.8%
50%	70,000	25,550,000	$1,709,289.16	$1,721,512.27	0.7%
70%	4,000	2,044,000	$136,049.12	$141,919.47	4.3%
70%	5,000	2,555,000	$169,336.43	$175,322.49	3.5%
70%	10,000	5,110,000	$335,772.95	$342,337.57	2.0%
70%	20,000	10,220,000	$668,646.00	$676,367.75	1.2%
70%	40,000	20,440,000	$1,334,392.11	$1,344,428.10	0.8%
70%	50,000	25,550,000	$1,667,265.16	$1,678,458.27	0.7%
70%	70,000	35,770,000	$2,333,011.26	$2,346,518.62	0.6%
90%	4,000	2,628,000	$171,690.39	$177,634.12	3.5%
90%	5,000	3,285,000	$213,888.00	$219,965.80	2.8%
90%	10,000	6,570,000	$424,876.11	$431,624.20	1.6%
90%	20,000	13,140,000	$846,852.32	$854,940.99	1.0%
90%	40,000	26,280,000	$1,690,804.74	$1,701,574.58	0.6%
90%	50,000	32,850,000	$2,112,780.95	$2,124,891.38	0.6%
90%	70,000	45,990,000	$2,956,733.36	$2,971,524.97	0.5%

PORTLAND GENERAL ELECTRIC
RATE DESIGN INPUT
SUMMARY - ALLOCATION OF 2011 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	$526,330	$24,171	$1,396		$25,567	$16,158	$2,361	$18,519	$29,798	$22,189	$51,248	$52,063	$155,298
Schedule 15	$1,339	$134	$4		$138	$41	$6	$47	$93	$70	$167	$119	$448
Schedule 32	$95,131	$4,386	$269		$4,654	$2,923	$427	$3,351	$4,655	$3,466	$9,334	$10,576	$28,032
Schedule 38	$2,367	$120	$7		$127	$73	$11	$83	$338	$252	$814	$1,226	$2,630
Schedule 47	$1,627	$78	$4		$82	$50	$7	$58	$215	$160	$1,177	$816	$2,368
Schedule 49	$5,016	$172	$13		$185	$154	$22	$176	$666	$496	$3,818	$2,334	$7,315
Schedule 83													
Secondary	$155,384	$5,794	$444		$6,238	$4,779	$698	$5,477	$7,840	$5,838	$13,626	$7,548	$34,851
Schedule 85													
Secondary		$6,247	$495	($336)	$6,406								
Primary		$573	$47	($33)	$586								
Class Total	$180,255					$5,545	$810	$6,355	$8,525	$6,348	$13,153	$6,248	$34,275
Schedule 89 1-4 MW													
Secondary		$1,473	$121	($82)	$1,512								
Primary		$1,362	$115	($81)	$1,397								
Class Total	$76,570					$2,323	$339	$2,663	$3,386	$2,521	$4,941	$1,512	$12,361
Schedule 89 GT 4 MW													
Secondary		$52	$4	($3)	$54						$231		$231
Primary		$4,247	$383	($269)	$4,362						$2,464		$2,464
Subtransmission		$1,851	$174	($124)	$1,902						$872		$872
Class Total	$138,962					$4,263	$623	$4,886	$4,226	$4,571			$8,797
Schedule 91	$6,035	$538	$20		$557	$185	$27	$212	$421	$314	$751	$535	$2,021
Schedules 92 & 94	$268	$12	$1		$12	$8	$1	$9	$8	$6	$15	$6	$35
Schedule 93	$31	$3	$0		$3	$1	$0	$1	$9	$7	$16	$21	$52
Totals	$1,189,316	$51,212	$3,498	($927)	$53,783	$36,503	$5,335	$41,838	$60,181	$46,237	$102,625	$83,005	$292,048

PORTLAND GENERAL ELECTRIC
RATE DESIGN INPUTS (CONTINUED)
SUMMARY - ALLOCATION OF 2011 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	$79,088	$14	$9,370	$1	$3,527	$0	$23,114	$2	$46,143	$4	$161,242	$22		$161,263	$886,977
Schedule 15	$139		$0		$0		$35		$66		$239	$0	$2,336	$2,575	$4,548
Schedule 32	$8,332	$11,786	$398	$241	$774	$469	$1,749	$1,059	$2,534	$1,535	$13,786	$15,090		$28,877	$160,044
Schedule 38	$15	$230	$0	$0	$1	$5	$1	$7	$8	$58	$25	$300		$325	$5,532
Schedule 47	$20	$444	$0	$4	$4	$48	$6	$79	$8	$117	$38	$692		$730	$4,865
Schedule 49	$2	$498	$0	$7	$0	$23	$0	$39	$0	$54	$2	$622		$624	$13,316
Schedule 83															
Secondary	$409	$13,199	$17	$229	$12	$184	$47	$731	$97	$1,277	$583	$15,619		$16,202	$218,153
Schedule 85															
Secondary		$3,903		$46		$29		$597		$4,514	$0	$9,090		$9,090	
Primary		$213		$3		$2		$41		$312	$0	$571		$571	$237,538
Schedule 89 1-4 MW															
Secondary		$582		$0		$2		$34		$1,241	$0	$1,858		$1,858	
Primary		$146		$0		$1		$25		$913	$0	$1,085		$1,085	$97,446
Schedule 89 GT 4 MW															
Secondary		$83		$0		$0		$1		$34	$0	$117		$117	
Primary		$118		$0		$0		$10		$360	$0	$488		$488	
Subtransmission		$154		$0		$0		$3		$113	$0	$270		$270	$163,405
Schedule 91	$896			$0		$0	$65		$282		$1,242	$0	$8,256	$9,498	$18,323
Schedules 92 & 94		$26		$0		$0		$5		$22	$0	$53		$53	$378
Schedule 93		$32		$0		$0		$1		$2	$0	$35		$35	$121
Totals	$88,900	$31,427	$9,786	$531	$4,317	$764	$25,015	$2,633	$49,140	$10,557	$177,158	$45,912	$10,592	$233,662	$1,810,647

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2011

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	$161,242	723,564	Customers	$18.57	per cust. per mo.	$161,239
Three-Phase	$22	67	Customers	$26.91	per cust. per mo.	$22
Trans. & Rel. Serv. Charge	$18,519	7,623,626	MWh	2.43	mills/kWh	$18,525
Distribution Charge	$155,298	7,623,626	MWh	20.37	mills/kWh	$155,293
Franchise Fees & Other	$25,567	7,623,626	MWh	3.35	mills/kWh	$25,539
Energy Charge	$526,330	7,623,626	MWh	69.04	mills/kWh	$526,335
Subtotal	$886,977					$886,954
Pricing						
Functional Costs						
Basic Charge						
Single-Phase		723,564	Customers	$10.00	per cust. per mo.	$86,828
Three-Phase		67	Customers	$14.00	per cust. per mo.	$11
Trans. & Rel. Serv. Charge		7,623,626	MWh	2.43	mills/kWh	$18,525
Distribution Charge		7,623,626	MWh	30.14	mills/kWh	$229,776
System Usage Charge Calculation						
Franchise Fees & Other		7,623,626	MWh	3.35	mills/kWh	$25,539
Cust Impact Offset		7,623,626	MWh	0.00	mills/kWh	$0
System Usage Charge		7,623,626	MWh	3.35	mills/kWh	$25,539
Energy Charge						
Block 1 (First 500 kWh)		3,887,765	MWh	59.00	mills/kWh	$229,378
Block 2 (501-1,000 kWh)		2,227,991	MWh	76.43	mills/kWh	$170,285
Block 3 (Over 1,000 kWh)		1,507,871	MWh	84.00	mills/kWh	$126,661
Subtotal						$887,004
					w/o CIO	$887,004
SCHEDULE 15						
Outdoor Area Lighting						
Allocations						
Functional Costs						
Basic Charge	$239	2,254	Customers	$8.85	per cust. per mo.	$239
Trans. & Rel. Serv. Charge	$47	24,166	MWh	1.95	mills/kWh	$47
Distribution Charge	$448	24,166	MWh	18.55	mills/kWh	$448
Franchise Fees & Other	$138	24,166	MWh	5.72	mills/kWh	$138
Energy Charge	$1,339	24,166	MWh	55.40	mills/kWh	$1,339
Fixed Charges	$2,336	24,166	MWh			$2,336
Subtotal	$4,548					$4,548
Pricing						
Functional Costs						
Trans. & Rel. Serv. Charge		24,166	MWh	1.95	mills/kWh	$47
Distribution Charge		24,166	MWh	28.45	mills/kWh	$688
System Usage Charge Calc						
Franchise Fees & Other		24,166	MWh	5.72	mills/kWh	$138
Cust Impact Offset		24,166	MWh	2.37	mills/kWh	$57
System Usage Charge		24,166	MWh	8.09	mills/kWh	$196
Energy Charge		24,166	MWh	55.40	mills/kWh	$1,339
Fixed Charges		24,166	MWh			$2,336
Subtotal						$4,605
					w/o CIO	$4,548

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2011

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	$13,786	53,535	Customers	$21.46	per cust. per mo.	$13,786
Three-Phase	$15,090	32,431	Customers	$38.78	per cust. per mo.	$15,092
Trans. & Rel. Serv. Charge	$3,351	1,466,414	MWh	2.28	mills/kWh	$3,343
Distribution Charge	$28,032	1,466,414	MWh	19.12	mills/kWh	$28,038
Franchise Fees & Other	$4,654	1,466,414	MWh	3.17	mills/kWh	$4,649
Energy Charge	$95,131	1,466,414	MWh	64.87	mills/kWh	$95,126
Subtotal	$160,044					$160,034
Pricing						
Functional Costs						
Basic Charge						
Single-Phase		53,535	Customers	$12.00	per cust. per mo.	$7,709
Three-Phase		32,431	Customers	$16.00	per cust. per mo.	$6,227
Trans. & Rel. Serv. Charge		1,466,414	MWh	2.28	mills/kWh	$3,343
Distribution Charge						
First 5 MWh		1,309,046	MWh	32.24	mills/kWh	$42,204
Over 5 MWh		157,368	MWh	5.00	mills/kWh	$787
System Usage Charge Calc						
Franchise Fees & Other		1,466,414	MWh	3.17	mills/kWh	$4,649
Cust Impact Offset		1,466,414	MWh	0.00	mills/kWh	$0
System Usage Charge		1,466,414	MWh	3.17	mills/kWh	$4,649
Energy Charge		1,466,414	MWh	64.87	mills/kWh	$95,126
Subtotal						$160,044
					w/o CIO	$160,044
SCHEDULE 38						
Time-of-Day G.S. >30 kW						
Allocations						
Functional Costs						
Basic						
Single-Phase	$25	46	Customers	$45.04	per cust. per mo.	$25
Three-Phase	$300	317	Customers	$78.95	per cust. per mo.	$300
Trans. & Rel. Serv. Charge	$83	38,502	MWh	2.16	per cust. per mo.	$83
Distribution Charges	$2,630	38,502	MWh	68.32	per cust. per mo.	$2,630
Franchise Fees & Other	$127	38,502	MWh	3.30	mills/kWh	$127
Energy Charge	$2,367	38,502	MWh	61.47	mills/kWh	$2,367
Subtotal	$5,532					$5,532
Pricing						
Functional Costs						
Basic						
Single-Phase		46	Customers	$20.00	per cust. per mo.	$11
Three-Phase		317	Customers	$25.00	per cust. per mo.	$95
Trans. & Rel. Serv. Charge		38,502	MWh	2.16	mills/kWh	$83
Distribution Charges		38,502	MWh	73.41	mills/kWh	$2,826
System Usage Charge						
Franchise Fees & Other		38,502	MWh	3.30	mills/kWh	$127
Cust Impact Offset		38,502	MWh	(22.99)	mills/kWh	($885)
System Usage Charge		38,502	MWh	(19.69)	mills/kWh	($758)
Energy Charge Calc						
On-Peak (special)		19,739	MWh	67.56	mills/kWh	$1,334
Off-Peak		18,763	MWh	55.06	mills/kWh	$1,033
Reactive Demand Charge		45,518	kVar	$0.50	kVar	$23
Subtotal						$4,647
					w/o CIO	$5,532

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2011

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	214	Customers	$29.91	per cust. per summ. mo.	$38
Three-Phase	$692	2,952	Customers	$39.05	per cust. per summ. mo.	$692
Trans. & Rel. Serv. Charge	$58	22,186	MWh	2.60	mills/kWh	$58
Distribution Charges	$2,368	22,186	MWh	106.71	mills/kWh	$2,367
Franchise Fees & Other	$82	22,186	MWh	3.70	mills/kWh	$82
Energy Charge	$1,627	22,186	MWh	73.35	mills/kWh	$1,627
Subtotal	$4,865					$4,865
Pricing						
Functional Costs						
Basic Charge						
Single-Phase		214	Customers	$25.00	per cust. per summ. mo.	$32
Three-Phase		2,952	Customers	$25.00	per cust. per summ. mo.	$443
Trans. & Rel. Serv. Charge		22,186	MWh	2.60	mills/kWh	$58
Distribution Charge Calc						
First 50 kWh per kW		7,315	MWh	131.61	mills/kWh	$963
Over 50 kWh per kW		14,871	MWh	111.61	mills/kWh	$1,660
System Usage Charge Calc						
Franchise Fees & Other		22,186	MWh	3.70	mills/kWh	$82
Cust Impact Offset		22,186	MWh	(83.12)	mills/kWh	($1,844)
System Usage Charge		22,186	MWh	(79.42)	mills/kWh	($1,762)
Energy Charge		22,186	MWh	73.35	mills/kWh	$1,627
Reactive Demand Charge		480	kVar	$0.50	kVar	$0
Subtotal with Consumer Impact Offset						$3,020
					w/o CIO	$4,865
SCHEDULE 49						
Irrig. & Drain. Pump. - > 30 kW						
Allocations						
Functional Costs						
Basic						
Single-Phase	$2	9	Customers	$46.06	per cust. per summ. mo.	$2
Three-Phase	$622	1,327	Customers	$78.11	per cust. per summ. mo.	$622
Trans. & Rel. Serv. Charge	$176	69,403	MWh	2.54	mills/kWh	$176
Distribution Charges	$7,315	69,403	MWh	105.40	mills/kWh	$7,315
Franchise Fees & Other	$185	69,403	MWh	2.67	mills/kWh	$185
Energy Charge	$5,016	69,403	MWh	72.27	mills/kWh	$5,016
Subtotal	$13,316					$13,317
Pricing						
Functional Costs						
Basic Charge						
Single-Phase		9	Customers	$30.00	per cust. per summ. mo.	$2
Three-Phase		1,327	Customers	$30.00	per cust. per summ. mo.	$239
Trans. & Rel. Serv. Charge		69,403	MWh	2.54	mills/kWh	$176
Distribution Charge Calc						
First 50 kWh per kW		20,097	MWh	125.09	mills/kWh	$2,514
Over 50 kWh per kW		49,306	MWh	105.09	mills/kWh	$5,182
System Usage Charge Calc						
Franchise Fees & Other		69,403	MWh	2.67	mills/kWh	$185
Cust Impact Offset		69,403	MWh	(95.00)	mills/kWh	($6,593)
System Usage Charge		69,403	MWh	(92.33)	mills/kWh	($6,408)
Energy Charge		69,403	MWh	72.27	mills/kWh	$5,016
Reactive Demand Charge		6,293	kVar	$0.50	kVar	$3
Subtotal with Consumer Impact Offset						$6,723
					w/o CIO	$13,316

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2011

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	$583	782	Customers	$62.18	per cust, per mo.	$583
Three-Phase Secondary	$15,619	10,245	Customers	$127.05	per cust, per mo.	$15,620
Transmission & Related Service Charge	$5,477	7,442,104	kW demand	$0.74	per kW demand	$5,507
Distribution Charges						
Feeder Backbone	$13,626	9,073,388	kW faccap	$1.50	per kW faccap	$13,610
Feeder Local Facilities	$7,548	9,073,388	kW faccap	$0.83	per kW faccap	$7,531
Subtransmission Charge	$5,838	7,442,104	kW demand	$0.78	per kW demand	$5,805
Substation Charge	$7,840	7,442,104	kW demand	$1.05	per kW demand	$7,814
Secondary Franchise Fees & Other	$6,238	2,422,868	MWh	2.57	mills/kWh	$6,227
Secondary COS Energy Charge	$155,384	2,422,868	MWh	64.13	mills/kWh	$155,379
Subtotal	$218,153					$218,075
Pricing						
Functional Costs						
Basic Charge						
Secondary Single-Phase		782	Customers	$20.00	per cust, per mo.	$188
Secondary Three-Phase		10,245	Customers	$30.00	per cust, per mo.	$3,688
Trans. & Rel. Serv. Charge						
First 30 kW		3,747,019	kW demand	$0.88	per kW demand	$3,297
Over 30 kW		3,695,085	kW demand	$0.88	per kW demand	$3,252
Distribution Charges						
Secondary Facilities Charge						
First 30 kW		3,969,598	kW faccap	$3.00	<= 30 kW faccap	$11,909
Over 30 kW		5,103,790	kW faccap	$2.50	> 30 kW faccap	$12,759
Secondary Demand Charge						
First 30 kW		3,747,019	kW demand	$1.83	per kW demand	$6,857
Over 30 kW		3,695,085	kW demand	$1.83	per kW demand	$6,762
Secondary System Usage Charge Calc						
Franchise Fees & Other		2,422,868	MWh	2.57	mills/kWh	$6,227
Cust Impact Offset		2,422,868	MWh	(1.92)	mills/kWh	($4,652)
Rate Design		2,422,868	MWh	3.15	mills/kWh	$7,632
System Usage Charge		2,422,868	MWh	3.80	mills/kWh	$9,207
Secondary COS Energy Charge		2,422,868	MWh	64.13	mills/kWh	$155,379
Reactive Demand Charge		366,921	kVar	$0.50	kVar	$183
Subtotal						$213,481
					w/o CIO	$218,133

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2011

Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULE 85						
General Service 201-1,000 kW						
Allocations						
Functional Costs						
Basic Charge						
Secondary	$9,090	1,877	Customers	$403.62	per cust, per mo.	$9,090
Primary	$571	130	Customers	$366.94	per cust, per mo.	$571
Transmission & Related Service Charge	$6,355	7,623,205	kW on-peak	$0.83	per kW demand	$6,327
Distribution Charges						
Feeder Backbone	$13,153	9,118,134	kW faccap	$1.44	per kW faccap	$13,130
Feeder Local Facilities	$6,248	9,118,134	kW faccap	$0.69	per kW faccap	$6,292
Subtransmission Charge	$6,348	7,649,713	kW on-peak	$0.83	per kW on-peak demand	$6,349
Substation Charge	$8,525	7,649,713	kW on-peak	$1.11	per kW on-peak demand	$8,491
Secondary Franchise Fees & Other	$6,406	2,704,457	MWh	2.37	mills/kWh	$6,410
Primary Franchise Fees & Other	$586	263,099	MWh	2.23	mills/kWh	$587
COS Energy Charge	$180,255	2,954,888	MWh	61.00	mills/kWh	$180,248
Subtotal	$237,538					$237,495
Pricing						
Functional Costs						
Basic Charge						
Secondary		1,877	Customers	$400.00	per cust, per mo.	$9,008
Primary		130	Customers	$360.00	per cust, per mo.	$561
Secondary Trans. & Rel. Serv. Charge		6,980,679	kW on-peak	$0.88	per kW demand	$6,143
Primary Trans. & Rel. Serv. Charge		642,526	kW on-peak	$0.85	per kW demand	$546
Distribution Charges						
Secondary Facilities Charge						
First 200 kW		4,504,000	kW faccap	$2.04	per kW faccap	$9,188
Over 200 kW		3,856,016	kW faccap	$2.04	per kW faccap	$7,866
Primary Facilities Charge						
First 200 kW		311,400	kW faccap	$1.97	per kW faccap	$613
Over 200 kW		446,717	kW faccap	$1.97	per kW faccap	$880
Secondary Demand Charge		7,007,187	kW on-peak	$1.95	per kW demand	$13,664
Primary Demand Charge		642,526	kW on-peak	$1.88	per kW demand	$1,208
Secondary System Usage Charge Calc						
Franchise Fees & Other		2,704,457	MWh	2.37	mills/kWh	$6,410
Cust Impact Offset		2,704,457	MWh	1.63	mills/kWh	$4,408
System Usage Charge		2,704,457	MWh	4.00	mills/kWh	$10,818
Primary System Usage Charge Calc						
Franchise Fees & Other		263,099	MWh	2.23	mills/kWh	$587
Cust Impact Offset		263,099	MWh	1.63	mills/kWh	$429
System Usage Charge		263,099	MWh	3.86	mills/kWh	$1,016
Secondary COS Energy Charge						
On-peak		1,731,398	MWh	65.39	mills/kWh	$113,216
Off-peak		960,392	MWh	53.60	mills/kWh	$51,477
Primary COS Energy Charge						
On-peak		166,936	MWh	63.47	mills/kWh	$10,595
Off-peak		96,163	MWh	51.68	mills/kWh	$4,970
Reactive Demand Charge		1,240,016	kVar	$0.50	kVar	$620
Subtotal						$242,389
					w/o CIO	$237,552

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2011

Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULE 89						
General Service						
Allocations						
Functional Costs						
Secondary Basic Charge	$1,976	113	Customers	$1,454.80	per cust, per mo.	$1,976
Primary Basic Charge	$1,574	113	Customers	$1,159.63	per cust, per mo.	$1,574
Subtransmission Basic Charge	$270	10	Customers	$2,248.77	per cust, per mo.	$270
Transmission & Related Service Charge	$7,549	7,198,505	kW on-peak	$1.05	per kW on-peak demand	$7,558
Distribution Charges						
Feeder Backbone	$8,508	9,397,785	kW faccap	$0.91	per kW faccap	$8,552
Feeder Local Facilities (1-4 MW only)	$1,512	3,430,753	kW faccap	$0.44	per kW faccap	$1,510
Subtransmission Demand Charge	$7,092	8,402,624	kW on-peak	$0.84	per kW on-peak demand	$7,058
Substation Demand Charge	$7,612	6,627,144	kW on-peak	$1.15	per kW on-peak demand	$7,621
Secondary Franchise Fees & Other	$1,565	684,369	MWh	2.29	mills/kWh	$1,567
Primary Franchise Fees & Other	$5,759	2,812,059	MWh	2.05	mills/kWh	$5,765
Subtransmission Franchise Fees & Other	$1,902	997,447	MWh	1.91	mills/kWh	$1,905
Energy Charge	$215,532	3,793,152	MWh	56.82	mills/kWh	$215,527
Subtotal	$260,851					$260,882
Pricing						
Functional Costs						
Secondary Basic Charge		113	Customers	$1,310.00	per cust, per mo.	$1,779
Primary Basic Charge		113	Customers	$1,040.00	per cust, per mo.	$1,411
Subtransmission Basic Charge		10	Customers	$2,020.00	per cust, per mo.	$242
Secondary Trans. & Rel. Serv. Charge		1,574,496	kW on-peak	$0.88	per kW on-peak demand	$1,386
Primary Trans. & Rel. Serv. Charge		4,680,377	kW on-peak	$0.85	per kW on-peak demand	$3,978
Subtransmission Trans. & Rel. Serv. Charge		943,632	kW on-peak	$0.84	per kW on-peak demand	$793
Distribution Charges						
Secondary Facilities Charge						
First 1,000 kW		1,358,000	kW faccap	$1.77	per kW faccap	$2,404
1,001-4,000 kW		643,973	kW faccap	$1.77	per kW faccap	$1,140
Greater than 4,000 kW		34,740	kW faccap	$0.38	per kW faccap	$13
Primary Facilities Charge						
First 1,000 kW		1,357,000	kW faccap	$1.73	per kW faccap	$2,348
1,001-4,000 kW		1,751,781	kW faccap	$1.73	per kW faccap	$3,031
Greater than 4,000 kW		2,357,798	kW faccap	$0.34	per kW faccap	$802
Subtransmission Facilities Charge						
First 1,000 kW		120,000	kW faccap	$1.73	per kW faccap	$208
1,001-4,000 kW		360,000	kW faccap	$1.73	per kW faccap	$623
Greater than 4,000 kW		1,414,494	kW faccap	$0.34	per kW faccap	$481
Secondary Demand Charge		1,625,728	kW on-peak	$2.05	per kW on-peak demand	$3,333
Primary Demand Charge		5,001,416	kW on-peak	$1.98	per kW on-peak demand	$9,903
Subtransmission Demand Charge		1,775,480	kW on-peak	$0.91	per kW on-peak demand	$1,616
Secondary System Usage Charge Calc						
Franchise Fees & Other		684,369	MWh	2.29	mills/kWh	$1,567
Cust Impact Offset		684,369	MWh	1.98	mills/kWh	$1,355
System Usage Charge		684,369	MWh	4.27	mills/kWh	$2,922
Primary System Usage Charge Calc						
Franchise Fees & Other		2,812,059	MWh	2.05	mills/kWh	$5,765
Cust Impact Offset		2,812,059	MWh	1.98	mills/kWh	$5,568
System Usage Charge		2,812,059	MWh	4.03	mills/kWh	$11,333
Subtransmission System Usage Charge Calc						
Franchise Fees & Other		997,447	MWh	1.91	mills/kWh	$1,905
Cust Impact Offset		997,447	MWh	1.98	mills/kWh	$1,975
System Usage Charge		997,447	MWh	3.89	mills/kWh	$3,880
Secondary Energy Charge						
On-peak		421,838	MWh	63.24	mills/kWh	$26,677
Off-peak		236,213	MWh	51.45	mills/kWh	$12,153
Primary Energy Charge						
On-peak		1,551,797	MWh	61.36	mills/kWh	$95,218
Off-peak		1,082,564	MWh	49.57	mills/kWh	$53,663
Subtransmission Energy Charge						
On-peak		288,551	MWh	60.54	mills/kWh	$17,469
Off-peak		212,188	MWh	48.75	mills/kWh	$10,344
Reactive Demand Charge		1,256,786	kVar	$0.50	kVar	$628
Subtotal						$269,776
					w/o CIO	$260,878

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2011

Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULE 91						
Street & Highway Lighting						
Allocations						
Functional Costs						
Basic Charge	$1,242	207	Customers	$500.02	per cust, per mo.	$1,242
Trans. & Rel. Serv. Charge	$212	108,918	MWh	1.95	mills/kWh	$212
Distribution Charge	$2,021	108,918	MWh	18.55	mills/kWh	$2,020
Franchise Fees & Other	$557	108,918	MWh	5.12	mills/kWh	$558
COS Energy Charge	$6,035	108,918	MWh	55.40	mills/kWh	$6,034
Fixed Charges	$8,256					$8,256
Subtotal	$18,323					$18,323
Pricing						
Functional Costs						
Trans. & Rel. Serv. Charge		108,918	MWh	1.95	mills/kWh	$212
Distribution Charge		108,918	MWh	29.95	mills/kWh	$3,262
System Usage Charge Calc						
Franchise Fees & Other		108,918	MWh	5.12	mills/kWh	$558
Cust Impact Offset		108,918	MWh	1.47	mills/kWh	$160
System Usage Charge		108,918	MWh	6.59	mills/kWh	$718
COS Energy Charge		108,918	MWh	55.40	mills/kWh	$6,034
Fixed Charges		108,918	MWh			$8,256
Subtotal						$18,482
					w/o CIO	$18,322
SCHEDULES 92 & 94						
Traffic Signals & Communication Devices						
Allocations						
Functional Costs						
Basic Charge	$53	17	Customers	$258.92	per cust, per mo.	$53
Trans. & Rel. Serv. Charge	$9	4,740	MWh	1.99	mills/kWh	$9
Distribution Charge	$35	4,740	MWh	7.38	mills/kWh	$35
Franchise Fees & Other	$12	4,740	MWh	2.63	mills/kWh	$12
COS Energy Charge	$268	4,740	MWh	56.63	mills/kWh	$268
Subtotal	$378					$378
Pricing						
Functional Costs						
Trans. & Rel. Serv. Charge		4,740	MWh	1.99	mills/kWh	$9
Distribution Charge		4,740	MWh	18.53	mills/kWh	$88
System Usage Charge Calc						
Franchise Fees & Other		4,740	MWh	2.63	mills/kWh	$12
Cust Impact Offset		4,740	MWh	4.47	mills/kWh	$21
System Usage Charge		4,740	MWh	7.10	mills/kWh	$34
COS Energy Charge		4,740	MWh	56.63	mills/kWh	$268
Subtotal						$399
					w/o CIO	$378
SCHEDULE 93						
Recreational Field Lighting						
Allocations						
Functional Costs						
Basic Charge	$35	23	Customers	$125.06	per cust, per mo.	$35
Trans. & Rel. Serv. Charge	$1	573	MWh	1.92	mills/kWh	$1
Distribution Charge	$52	573	MWh	89.98	mills/kWh	$52
Franchise Fees & Other	$3	573	MWh	5.07	mills/kWh	$3
Energy Charge	$31	573	MWh	54.70	mills/kWh	$31
Subtotal	$121					$121
Pricing						
Functional Costs						
Basic Charge		23	Customers	$30.00	per cust, per mo.	$8
Trans. & Rel. Serv. Charge		573	MWh	1.92	mills/kWh	$1
Distribution Charge		573	MWh	135.79	mills/kWh	$78
System Usage Charge Calc						
Franchise Fees & Other		573	MWh	5.07	mills/kWh	$3
Cust Impact Offset		573	MWh	(22.57)		($13)
System Usage Charge		573	MWh	(17.50)	mills/kWh	($10)
Energy Charge		573	MWh	54.70	mills/kWh	$31
Subtotal						$108
					w/o CIO	$121

PORTLAND GENERAL ELECTRIC
CONSUMER IMPACT OFFSET

Grouping	Cycle MWH	Revenues at 2010 Prices ($000)	2011 Allocated Costs ($000)	Percent Change	Maximum Change	Minimum Change	Impact Offset Cap	Impact Offset Floor	Cap Impact Offset MWH	Floor Impact Offset MWH	Spread Offset Net Cap/Floor	CIO mills/kWh	CIO Revenues
Schedule 7	7,623,626	$814,982	$886,977	8.8%	9.3%	0.0%	$0	$0	0	0		0.00	$0
Schedule 15	24,166	$4,515	$4,548	0.7%	9.3%	0.0%	$0	$0	0	0	$39	2.37	$57
Schedule 32	1,466,414	$147,875	$160,044	8.2%	9.3%	0.0%	$0	$0	0	0		0.00	$0
Schedule 38	38,502	$4,046	$5,532	36.7%	14.8%	0.0%	($885)	$0	(38,502)	0		(22.99)	($885)
Schedule 47	22,186	$2,630	$4,865	85.0%	14.8%	0.0%	($1,844)	$0	(22,186)	0		(83.12)	($1,844)
Schedule 49	69,403	$5,811	$13,316	129.1%	14.8%	0.0%	($6,593)	$0	(69,403)	0		(95.00)	($6,593)
Schedule 83	2,422,868	$195,372	$218,153	11.7%	9.3%	0.0%	($4,649)	$0	(2,422,868)	0		(1.92)	($4,652)
Schedule 85	2,954,888	$229,215	$237,588	3.7%	9.3%	0.0%	$0	$0	0	0	$4,817	1.63	$4,816
Schedule 89	3,793,152	$263,312	$261,728	-0.6%	9.3%	0.0%	$0	$1,584	0	3,793,152	$6,183	1.98	$7,510
Schedule 91	108,918	$18,124	$18,323	1.1%	9.3%	0.0%	$0	$0	0	0	$178	1.47	$160
Schedule 92	4,740	$392	$378	-3.4%	9.3%	0.0%	$0	$13	0	4,740	$8	4.47	$21
Schedule 93	573	$94	$121	28.5%	14.8%	0.0%	($13)	$0	(573)	0		(22.57)	($13)
COS TOTALS	18,529,435												
Sch 485 Energy	12,667									0	$21	1.63	$21
Sch 76/489 Energy	700,724									700,724	$1,142	1.98	$1,387
Total Cycle Energy	19,242,826	$1,686,369	$1,811,574	7.4%			($13,985)	$1,597	(2,553,532)	4,498,616	$12,387		($14)

Cap on Rate Change	1.25	(core schedules)
Cap on Rate Change	2.00	(irrigation, sch 38, 93)
Cap on CIO (mills/kWh)	(95.00)	
Floor on Rate Change	0.00	

PORTLAND GENERAL ELECTRIC
2011 Test Period Functionalized Revenue Requirement

FUNCTION	AMOUNT	ADJUST	TOTAL
PRODUCTION	$1,189,349	($940)	$1,188,409
TRANSMISSION	$36,519		$36,519
ANCILLARY	$5,338		$5,338
DISTRIBUTION	$487,310	$969	$488,279
METERING	$5,084		$5,084
BILLING	$27,665		$27,665
CONSUMER	$59,731		$59,731
TOTALS	$1,810,996		$1,811,025

Note: Distribution adjustment is employee discount
Note: Production adjustment is Schedule 129 Long-Term Transition Adjustment

PORTLAND GENERAL ELECTRIC
UNBUNDLED 2011 COSTS ($000)

	Unbundled Costs	Adjusted to Cycle
Fixed Generation Revenue Requirement	$442,157	$442,145
Net Variable Power Costs	$747,192	$747,171
Production Costs	$1,189,349	$1,189,316
Ancillary Services	$5,338	$5,335
Transmission	$36,519	$36,503
Distribution Services	$487,310	
Franchise & OPUC Fees	($51,242)	
Uncollectibles	($10,323)	
Trojan Decommissioning	($3,500)	
Employee Discount	$969	$969
Distribution Costs	$423,214	$422,967
Consumer Services		
Metering Services	$5,084	$5,081
Billing Services	$27,665	$27,649
Other Consumer Services	$59,731	$59,696
Franchise & OPUC Fees	$51,242	$51,212
Uncollectibles	$10,323	$10,317
Trojan Decommissioning	$3,500	$3,498
Schedule 129	($940)	($927)
Totals	$1,811,025	$1,810,647
Net of employee discount	$1,810,056	$1,809,678
Net of Sch 129	$1,810,996	$1,810,605
Calendar MWH	19,254,051	
Cycle MWH	19,242,826	
Cycle/Cal Ratio	99.94%	
COS Calendar Energy MWH	18,537,436	
COS Cycle MWH	18,529,435	
Cycle/Cal Ratio	99.96%	

PORTLAND GENERAL ELECTRIC
Changes in Revenues Resulting from 2011 Price Changes ($000)

Category	2010 Current	2011 Proposed	Change	
Table 1 COS	$1,680,588	$1,804,111	$123,523	
Direct Access	$4,858	$6,471	$1,613	
Cycle Totals	$1,685,446	$1,810,582	$125,136	
Calendar Adjustment	1.00022	1.00022		
Calendar Basis Retail Revenues	$1,685,809	$1,810,972	$125,163	7.4%

Reconciliation of Revenues and Revenue Requirement

Revenue Requirement	$1,810,996
Calendar Revenues	$1,810,972
Base Rate Difference	($24)

PORTLAND GENERAL ELECTRIC
ALLOCATION OF PRODUCTION COSTS TO COS CUSTOMERS
2011

Grouping	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	7,625,447	$661,667	49.65%	$349,322	$1,010,989	44.26%	$526,456	$526,330
Schedule 15	24,166	$1,920	0.09%	$651	$2,571	0.11%	$1,339	$1,339
Schedule 32	1,468,300	$126,206	8.06%	$56,716	$182,922	8.01%	$95,254	$95,131
Schedule 38	38,493	$3,250	0.18%	$1,294	$4,544	0.20%	$2,366	$2,367
Schedule 47	22,364	$1,806	0.19%	$1,345	$3,150	0.14%	$1,641	$1,627
Schedule 49	69,230	$5,565	0.57%	$4,043	$9,608	0.42%	$5,003	$5,016
Schedule 83	2,427,906	$209,019	12.79%	$89,997	$299,016	13.09%	$155,708	$155,384
Schedule 85	2,969,833	$253,251	13.31%	$93,666	$346,917	15.19%	$180,651	$180,255
Schedule 89 1-4 MW	1,264,503	$105,547	5.66%	$39,806	$145,353	6.36%	$75,690	$76,570
Schedule 89 GT 4 MW	2,512,964	$203,081	9.05%	$63,673	$266,754	11.68%	$138,908	$138,962
Schedule 91	108,918	$8,652	0.42%	$2,936	$11,589	0.51%	$6,035	$6,035
Schedule 92/94	4,740	$395	0.02%	$120	$516	0.02%	$268	$268
Schedule 93	573	$49	0.00%	$11	$60	0.00%	$31	$31
TOTAL	18,537,436	$1,580,407	100.0%	$703,581	$2,283,988	100.00%	$1,189,349	$1,189,316
Simple Cycle Proxy Plant $/kW				$191.18		**TARGET**	**$1,189,349**	
Projected Peak Load				3,680.2				
Marginal Capacity Costs ($000)				$703,581				

PORTLAND GENERAL ELECTRIC
Marginal Energy Costs: 2011 Test Period

Grouping	Busbar MWh	Marginal Energy Cost	Percent
Schedule 7	8,255,309	$661,666,837	41.87%
Schedule 15	26,162	$1,919,711	0.12%
Schedule 32	1,589,581	$126,205,813	7.99%
Schedule 38	41,673	$3,250,150	0.21%
Schedule 47	24,212	$1,805,853	0.11%
Schedule 49	74,948	$5,564,572	0.35%
Schedule 83	2,628,451	$209,019,289	13.23%
Schedule 85	3,205,834	$253,250,715	16.02%
Schedule 89 1-4 MW	1,347,109	$105,547,156	6.68%
Schedule 89 GT 4 MW	2,627,965	$203,080,973	12.85%
Schedule 91	117,915	$8,652,285	0.55%
Schedule 92/94	5,132	$395,165	0.03%
Schedule 93	620	$48,669	0.00%
TOTAL	19,944,911	$1,580,407,189	100.00%

PORTLAND GENERAL ELECTRIC
SCCT Proxy Cost

	SCCT Proxy Capital Cost $/kW		
1	SCCT Installed Cost	$/kW	$1,171
2	Real Carrying Charge		11.20%
3	Annualized SCCT Cost	$/kW-yr	$131.25
4	Fixed O&M	$/kW-yr	$3.11
5	Fixed Gas Transport	$/kW-yr	$36.34
6	Reserve Margin (12%)	$/kW-yr	$20.48
7	Total	$/kW-yr	$191.18

PORTLAND GENERAL ELECTRIC
ALLOCATION OF TRANSMISSION REVENUE REQUIREMENT
2011

Grouping	Generation Allocation Percent	Class Revenue Requirement
Schedule 7	44.26%	$16,158
Schedule 15	0.11%	$41
Schedule 32	8.01%	$2,923
Schedule 38	0.20%	$73
Schedule 47	0.14%	$50
Schedule 49	0.42%	$154
Schedule 83	13.09%	$4,779
Schedule 85	15.19%	$5,545
Schedule 89 1-4 MW	6.36%	$2,323
Schedule 89 GT 4 MW	11.68%	$4,263
Schedule 91	0.51%	$185
Schedule 92/94	0.02%	$8
Schedule 93	0.00%	$1
Target	100.00%	$36,503

PORTLAND GENERAL ELECTRIC
ALLOCATION OF ANCILLARY SERVICE COSTS
2011

Grouping	Production Allocation Percent	Allocated Costs ($000)
Schedule 7	44.26%	$2,361
Schedule 15	0.11%	$6
Schedule 32	8.01%	$427
Schedule 38	0.20%	$11
Schedule 47	0.14%	$7
Schedule 49	0.42%	$22
Schedule 83	13.09%	$698
Schedule 85	15.19%	$810
Schedule 89 1-4 MW	6.36%	$339
Schedule 89 GT 4 MW	11.68%	$623
Schedule 91	0.51%	$27
Schedule 92	0.02%	$1
Schedule 93	0.00%	$0
TOTAL	100.00%	$5,335
	TARGET	$5,335

PORTLAND GENERAL ELECTRIC

Applicable 2011 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	3,225	$149.89	$483,327
	SCHEDULE 2 - REACTIVE SUPPLY & VOLTAGE CONTROL		$/kW year	
2	12 CP kW Average	3,224,542	$0.461	$1,486,514
	SCHEDULE 3 - REGULATION & FREQUENCY RESPONSE		$/kW month	
3	Billing Determinant: Sum of Monthly Average 12 CP KW	38,694,500	$0.09	$3,367,776
	Charge: $6.695 per kW per month x .013			
4		**ANCILLARY SERVICES TOTAL**		$5,337,616

PORTLAND GENERAL ELECTRIC
ALLOCATION OF TROJAN DECOMMISSIONING COSTS
2011

Grouping	Cycle Energy (MWh)	Line Losses	Busbar Energy	Allocation Percent	Costs ($000)
Schedule 7	7,623,626	8.26%	8,253,338	39.91%	$1,396
Schedule 15	24,166	8.26%	26,162	0.13%	$4
Schedule 32	1,466,414	8.26%	1,587,539	7.68%	$269
Schedule 38	38,502	8.26%	41,682	0.20%	$7
Schedule 47	22,186	8.26%	24,019	0.12%	$4
Schedule 49	69,403	8.26%	75,135	0.36%	$13
Schedule 83-S	2,422,868	8.26%	2,622,997	12.68%	$444
Schedule 85-S	2,704,457	8.26%	2,927,845	14.16%	$495
Schedule 89-S 1-4 MW	662,167	8.26%	716,862	3.47%	$121
Schedule 89-S GT 4 MW	22,202	8.26%	24,036	0.12%	$4
Schedule 85-P	263,099	4.84%	275,833	1.33%	$47
Schedule 89-P 1-4 MW	650,642	4.84%	682,133	3.30%	$115
Schedule 89-P GT 4 MW	2,161,417	4.84%	2,266,029	10.96%	$383
Schedule 89-T	997,447	3.37%	1,031,061	4.99%	$174
Schedule 91	108,918	8.26%	117,915	0.57%	$20
Schedule 92	4,740	8.26%	5,132	0.02%	$1
Schedule 93	573	8.26%	620	0.00%	$0
TOTAL	19,242,826		20,678,338		$3,498
				TARGET	$3,498

PORTLAND GENERAL ELECTRIC
ALLOCATION OF FRANCHISE AND OPUC FEES
2011

Grouping	Current Revenues	Allocation Percent	Costs ($000)
Schedule 7	$814,982	47.20%	$24,171
Schedule 15	$4,515	0.26%	$134
Schedule 32	$147,875	8.56%	$4,386
Schedule 38	$4,046	0.23%	$120
Schedule 47	$2,630	0.15%	$78
Schedule 49	$5,811	0.34%	$172
Schedule 83-S	$195,372	11.31%	$5,794
Schedule 85-S	$210,631	12.20%	$6,247
Schedule 89-S 1-4 MW	$49,657	2.88%	$1,473
Schedule 89-S GT 4 MW	$1,768	0.10%	$52
Schedule 85-P	$19,305	1.12%	$573
Schedule 89-P 1-4 MW	$45,940	2.66%	$1,362
Schedule 89-P GT 4 MW	$143,200	8.29%	$4,247
Schedule 89-T	$62,429	3.62%	$1,851
Schedule 91	$18,124	1.05%	$538
Schedule 92 & 94	$392	0.02%	$12
Schedule 93	$94	0.01%	$3
TOTAL	$1,726,772	100.00%	$51,212
		TARGET	$51,212

Note: DA customers priced at COS for allocation

PORTLAND GENERAL ELECTRIC
ALLOCATION OF SCHEDULE 129 TRANSITION ADJUSTMENT
2011

Grouping	Cycle Energy	Percent	Allocations ($000)
Schedule 85-S	2,704,457	36.2%	($336)
Schedule 89-S 1-4 MW	662,167	8.9%	($82)
Schedule 89-S GT 4 MW	22,202	0.3%	($3)
Schedule 85-P	263,099	3.5%	($33)
Schedule 89-P 1-4 MW	650,642	8.7%	($81)
Schedule 89-P GT 4 MW	2,161,417	29.0%	($269)
Schedule 89-T	997,447	13.4%	($124)
TOTAL	7,461,431	100.00%	($927)
		TARGET	($927)

Note: cycle energy includes direct access customers

PORTLAND GENERAL ELECTRIC
ALLOCATION OF UNCOLLECTIBLES
2011

Grouping	Marginal Cost Allocation Percent	Class Revenue Requirement
Schedule 7		
Single Phase	90.83%	$9,370
Three Phase	0.01%	$1
Schedule 15		
Residential	0.00%	$0
Commercial	0.00%	$0
Schedule 32		
Single Phase	3.85%	$398
Three Phase	2.33%	$241
Schedule 38		
Single Phase	0.00%	$0
Three Phase	0.00%	$0
Schedule 47		
Single Phase	0.00%	$0
Three Phase	0.03%	$4
Schedule 49		
Single Phase	0.00%	$0
Three Phase	0.07%	$7
Schedule 83		
Single Phase	0.17%	$17
Three Phase	2.22%	$229
Schedule 85		
Secondary	0.45%	$46
Primary	0.03%	$3
Schedule 89 1-4 MW		
Secondary	0.00%	$0
Primary	0.00%	$0
Schedule 89 GT 4 MW		
Secondary	0.00%	$0
Primary	0.00%	$0
Subtransmission	0.00%	$0
Schedule 91	0.00%	$0
Schedule 92/94	0.00%	$0
Schedule 93	0.00%	$0
TOTAL	100.00%	$10,317
	TARGET	$10,317

PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION COST
2011

Grouping			Usages	Units & Basis	Marginal Unit Cost	Marginal Cost Revenues	Class Revenue Requirement
Schedule 7 Residential							
CUSTOMER	Meters						
		Single-Phase Customers	723,564	Customers	$17.24	$12,474	$13,919
		Three-Phase Customers	67	Customers	$46.87	$3	$4
	Service & Transformer						
		Single-Phase Customers	723,564	Customers	$80.72	$58,406	$65,169
		Three-Phase Customers	67	Customers	$140.75	$9	$11
FACILITIES	Feeder Backbone						
		Single-Phase Customers	2,027,592	kW, rateclass peak	$22.65	$45,925	$51,243
		Three-Phase Customers	188	kW, rateclass peak	$22.65	$4	$5
	Feeder Local Facilities						
		Single-Phase Customers	2,894,254	Design Demand	$16.12	$46,655	$52,058
		Three-Phase Customers	268	Design Demand	$16.12	$4	$5
DEMAND	Subtransmission		2,054,344	kW, rateclass peak	$9.68	$19,886	$22,189
	Substation		2,027,780	kW, rateclass peak	$13.17	$26,706	$29,798
SUBTOTAL						$210,074	$234,400
Schedule 15 Residential Outdoor Area Lighting							
CUSTOMER	Customer Service		10,081	Lights	$4.17	$42	$47
	Transformer		10,081	Lights	$1.52	$15	$17
FACILITIES	Feeder Backbone		1,880	kW, rateclass peak	$23.48	$44	$49
	Feeder Local Facilities		1,880	Design Demand	$16.74	$31	$35
DEMAND	Subtransmission		1,905	kW, rateclass peak	$9.68	$18	$21
	Substation		1,880	kW, rateclass peak	$13.17	$25	$28
FIXED	Luminaires & Poles						$691
SUBTOTAL						$176	$887
Schedule 15 Commercial Outdoor Area Lighting							
CUSTOMER	Customer Service		11,770	Lights	$4.17	$49	$55
	Transformer		11,770	Lights	$1.52	$18	$20
FACILITIES	Feeeder Backbone		4,478	kW, rateclass peak	$23.48	$105	$117
	Feeder Local Facilities		4,478	Design Demand	$16.74	$75	$84
DEMAND	Subtransmission		4,537	kW, rateclass peak	$9.68	$44	$49
	Substation		4,478	kW, rateclass peak	$13.17	$59	$66
FIXED	Luminaires & Poles						$1,645
SUBTOTAL						$350	$2,036
Schedule 15 Outdoor Area Lighting							
CUSTOMER	Customer Service						$102
	Transformer						$37
FACILITIES	Feeeder Backbone						$167
	Feeder Local Facilities						$119
DEMAND	Subtransmission						$70
	Substation						$93
FIXED	Luminaires & Poles						$2,336
SUBTOTAL							$2,923

PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION COST
2011

Grouping			Usages	Units & Basis	Marginal Unit Cost	Marginal Cost Revenues	Class Revenue Requirement
Schedule 32 Small Non-residential General Service							
CUSTOMER	Meters						
		Single-Phase Customers	53,535	Customers	$17.83	$955	$1,065
		Three-Phase Customers	32,431	Customers	$62.12	$2,015	$2,248
	Service & Transformer						
		Single-Phase Customers	53,535	Customers	$121.65	$6,513	$7,267
		Three-Phase Customers	32,431	Customers	$263.58	$8,548	$9,538
FACILITIES	Feeder Backbone						
		Single-Phase Customers	133,472	kW, rateclass peak	$26.41	$3,525	$3,933
		Three-Phase Customers	183,284	kW, rateclass peak	$26.41	$4,841	$5,401
	Feeder Local Facilities						
		Single-Phase Customers	267,674	Design Demand	$22.76	$6,092	$6,798
		Three-Phase Customers	369,714	Design Demand	$9.16	$3,387	$3,779
DEMAND	Subtransmission		320,905	kW, rateclass peak	$9.68	$3,106	$3,466
	Substation		316,756	kW, rateclass peak	$13.17	$4,172	$4,655
SUBTOTAL						$43,152	$48,149
Schedule 38 General Service							
CUSTOMER	Meters						
		Single-Phase Customers	46	Customers	$41.81	$2	$2
		Three-Phase Customers	317	Customers	$65.27	$21	$23
	Service & Transformer						
		Single-Phase Customers	46	Customers	$244.24	$11	$12
		Three-Phase Customers	317	Customers	$585.53	$185	$207
FACILITIES	Feeder Backbone						
		Single-Phase Customers	1,305	kW, rateclass peak	$31.68	$41	$46
		Three-Phase Customers	21,727	kW, rateclass peak	$31.68	$688	$768
	Feeder Local Facilities						
		Single-Phase Customers	2,284	Design Demand	$18.83	$43	$48
		Three-Phase Customers	39,225	Design Demand	$26.91	$1,056	$1,178
DEMAND	Subtransmission		23,333	kW, rateclass peak	$9.68	$226	$252
	Substation		23,032	kW, rateclass peak	$13.17	$303	$338
SUBTOTAL						$2,576	$2,875
Schedule 47 Irrigation & Drainage Service - < 30 kW							
CUSTOMER	Meters						
		Single-Phase Customers	214	Customers	$41.81	$9	$10
		Three-Phase Customers	2,952	Customers	$56.26	$166	$185
	Service & Transformer						
		Single-Phase Customers	214	Customers	$43.96	$9	$10
		Three-Phase Customers	2,952	Customers	$78.65	$232	$259
FACILITIES	Feeder Backbone						
		Single-Phase Customers	569	kW, rateclass peak	$72.18	$41	$46
		Three-Phase Customers	14,039	kW, rateclass peak	$72.18	$1,013	$1,131
	Feeder Local Facilities						
		Single-Phase Customers	1,584	Design Demand	$50.75	$80	$90
		Three-Phase Customers	24,206	Design Demand	$26.91	$651	$727
DEMAND	Subtransmission		14,800	kW, rateclass peak	$9.68	$143	$160
	Substation		14,608	kW, rateclass peak	$13.17	$192	$215
SUBTOTAL						$2,538	$2,832

PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION COST
2011

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	9	Customers	$41.81	$0	$0
		Three-Phase Customers	1,327	Customers	$94.95	$126	$141
	Service & Transformer						
		Single-Phase Customers	9	Customers	$122.52	$1	$1
		Three-Phase Customers	1,327	Customers	$241.72	$321	$358
FACILITIES	Feeder Backbone						
		Single-Phase Customers	155	kW, rateclass peak	$75.46	$12	$13
		Three-Phase Customers	45,189	kW, rateclass peak	$75.46	$3,410	$3,805
	Feeder Local Facilities						
		Single-Phase Customers	426	Design Demand	$43.89	$19	$21
		Three-Phase Customers	76,966	Design Demand	$26.94	$2,073	$2,314
DEMAND	Subtransmission		45,938	kW, rateclass peak	$9.68	$445	$496
	Substation		45,344	kW, rateclass peak	$13.17	$597	$666
SUBTOTAL						$7,004	$7,815
Schedule 83 General Service (31-200 kW)							
CUSTOMER	Meters						
		Single-Phase Customers	782	Customers	$41.81	$33	$36
		Three-Phase Customers	10,245	Customers	$57.92	$593	$662
	Service & Transformer						
		Single-Phase Customers	782	Customers	$427.62	$334	$373
		Three-Phase Customers	10,245	Customers	$1,096.71	$11,236	$12,537
FACILITIES	Feeder Backbone						
		Single-Phase Customers	21,593	kW, rateclass peak	$22.89	$494	$551
		Three-Phase Customers	511,892	kW, rateclass peak	$22.89	$11,717	$13,074
	Feeder Local Facilities						
		Single-Phase Customers	30,557	Design Demand	$18.37	$561	$626
		Three-Phase Customers	726,382	Design Demand	$8.54	$6,203	$6,922
DEMAND	Subtransmission		540,474	kW, rateclass peak	$9.68	$5,232	$5,838
	Substation		533,485	kW, rateclass peak	$13.17	$7,026	$7,840
SUBTOTAL						$43,430	$48,459
Schedule 85 General Service (201-1,000 kW)							
CUSTOMER	Meters						
		Secondary Customers	1,877	Customers	$126.92	$238	$266
		Primary Customers	130	Customers	$739.95	$96	$107
	Service & Transformer						
		Secondary Customers	1,877	Customers	$1,737.06	$3,260	$3,637
		Primary Customers	130	Customers	$729.51	$95	$106
FACILITIES	Feeder Backbone		580,135	kW, rateclass peak	$20.32	$11,788	$13,153
	Feeder Local Facilities		759,830	Design Demand	$7.37	$5,600	$6,248
DEMAND	Subtransmission		587,734	kW, rateclass peak	$9.68	$5,689	$6,348
	Substation		580,135	kW, rateclass peak	$13.17	$7,640	$8,525
SUBTOTAL						$34,407	$38,391

PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION COST
2011

Grouping			Usages	Units & Basis	Marginal Unit Cost	Marginal Cost Revenues	Class Revenue Requirement
Schedule 89 General Service (1,001-4,000 kW)							
CUSTOMER	Meters						
		Secondary Meters	110	Customers	$138.16	$15	$17
		Primary Meters	81	Customers	$739.95	$60	$67
	Service & Transformer						
		Secondary Customers	110	Customers	$4,594.87	$506	$565
		Primary Customers	81	Customers	$869.70	$71	$79
FACILITIES	Feeder Backbone		230,414	kW, rateclass peak	$19.22	$4,429	$4,941
	Feeder Local Facilities		285,896	Design Demand	$4.74	$1,355	$1,512
DEMAND	Subtransmission		233,432	kW, rateclass peak	$9.68	$2,260	$2,521
	Substation		230,414	kW, rateclass peak	$13.17	$3,035	$3,386
SUBTOTAL						$11,730	$13,088
Schedule 89 General Service (4,000 plus kW)							
CUSTOMER	Meters						
		Secondary Meters	3	Customers	$138.16	$0	$0
		Primary Meters	32	Customers	$739.95	$24	$26
		Substation Meters	10	Customers	$13,800.01	$138	$154
	Service & Transformer						
		Secondary Customers	3	Customers	$24,515.53	$74	$82
		Primary Customers	32	Customers	$2,555.63	$82	$91
FACILITIES	Feeder Backbone						
		Secondary Customers	3	Customers	$68,998.00	$207	$231
		Primary Customers	32	Customers	$68,998.00	$2,208	$2,464
		Subtransmission 115 kV Feeder	10	Customers	$78,156.00	$782	$872
DEMAND	Subtransmission		423,179	kW, rateclass peak	$9.68	$4,096	$4,571
	Substation (Sec. & Prim. Only)		287,582	kW, rateclass peak	$13.17	$3,787	$4,226
SUBTOTAL						$11,398	$12,718
Schedule 91 Streetlighting & Highway Lighting							
CUSTOMER	Customer Service		156,566	Lights	$4.17	$652	$728
	Transformers		156,566	Lights	$0.96	$150	$168
FACILITIES	Feeder Backbone		28,658	kW, rateclass peak	$23.48	$673	$751
	Feeder Local Facilities		28,658	Design Demand	$16.74	$480	$535
DEMAND	Subtransmission		29,034	kW, rateclass peak	$9.68	$281	$314
	Substation		28,658	kW, rateclass peak	$13.17	$377	$421
FIXED	Luminaires & Poles						**$8,256**
SUBTOTAL						$2,614	$11,173

PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION COST
2011

Grouping		Usages	Units & Basis	Marginal Unit Cost	Marginal Cost Revenues	Class Revenue Requirement
Schedules 92 & 94 Traffic Signals & Communications Devices						
CUSTOMER	Service & Transformer	1,663	Intersections	$13.89	$23	$26
FACILITIES	Feeder Backbone	567	kW, rateclass peak	$23.48	$13	$15
	Feeder Local Facilities	567	Design Demand	$8.86	$5	$6
DEMAND	Subtransmission	575	kW, rateclass peak	$9.68	$6	$6
	Substation	567	kW, rateclass peak	$13.17	$7	$8
SUBTOTAL					$54	$61
Schedule 93 Stadium Lighting						
CUSTOMER	Meters	23	Customers	$1,116.44	$26	$29
	Service & Transformer	23	Customers	$116.25	$3	$3
FACILITIES	Feeder Backbone	595	kW, rateclass peak	$23.48	$14	$16
	Feeder Local Facilities	2,093	Design Demand	$8.86	$19	$21
DEMAND	Subtransmission	603	kW, rateclass peak	$9.68	$6	$7
	Substation	595	kW, rateclass peak	$13.17	$8	$9
SUBTOTAL					$75	$83
Summary						
CUSTOMER	Meters	827,753	Customers		$16,994	$18,962
	Service & Transformer		Customers		$90,102	$100,536
	Customer Service	178,417	Lights		$743	$829
FACILITIES	Feeder Backbone	3,807,732	kW, rateclass peak		$91,975	$102,625
	Feeder Local Facilities	5,481,404	Design Demand		$74,390	$83,005
DEMAND	Subtransmission	4,280,793	kW, rateclass peak		$41,438	$46,237
	Substation	4,095,314	kW rateclass Peak		$53,935	$60,181
FIXED	Luminaires & Poles					$10,592
TOTALS					$369,578	$422,967
					TARGET	$422,967
				EQUAL PERCENT		111.6%

PORTLAND GENERAL ELECTRIC
ALLOCATION OF METERING REVENUE REQUIREMENT
2011

Grouping	Customers	Marginal Unit Cost $ per Customer	Marginal Cost Revenues	Class Revenue Requirement
Schedule 7				
Single Phase	723,564	$2.89	$2,091	$3,527
Three Phase	67	$2.89	$0	$0
Schedule 15				
Residential	882	$0.00	$0	$0
Commercial	1,372	$0.00	$0	$0
Schedule 32				
Single Phase	53,535	$8.57	$459	$774
Three Phase	32,431	$8.57	$278	$469
Schedule 38				
Single Phase	46	$9.28	$0	$1
Three Phase	317	$9.28	$3	$5
Schedule 47				
Single Phase	214	$9.73	$2	$4
Three Phase	2,952	$9.73	$29	$48
Schedule 49				
Single Phase	9	$10.47	$0	$0
Three Phase	1,327	$10.47	$14	$23
Schedule 83				
Single Phase	782	$9.00	$7	$12
Three Phase	12,122	$9.00	$109	$184
Schedule 85				
Secondary	1,877	$9.01	$17	$29
Primary	130	$9.01	$1	$2
Schedule 89 1-4 MW				
Secondary	110	$8.35	$1	$2
Primary	81	$8.35	$1	$1
Schedule 89 GT 4 MW				
Secondary	3	$8.35	$0	$0
Primary	32	$8.35	$0	$0
Subtransmission	10	$8.35	$0	$0
Schedule 91	207	$0.00	$0	$0
Schedule 92/94	17	$0.00	$0	$0
Schedule 93	23	$9.19	$0	$0
TOTAL	832,108		$3,013	$5,081
			TARGET	$5,081
		EQUAL PERCENT		169%

PORTLAND GENERAL ELECTRIC
ALLOCATION OF BILLING REVENUE REQUIREMENT
2011

Grouping	Customers	Marginal Unit Cost $ per Customer	Marginal Cost Revenues	Class Revenue Requirement
Schedule 7				
Single Phase	723,564	$22.60	$16,353	$23,114
Three Phase	67	$22.60	$2	$2
Schedule 15				
Residential	882	$10.13	$9	$13
Commercial	1,372	$11.35	$16	$22
Schedule 32				
Single Phase	53,535	$23.11	$1,237	$1,749
Three Phase	32,431	$23.11	$749	$1,059
Schedule 38				
Single Phase	46	$15.07	$1	$1
Three Phase	317	$15.07	$5	$7
Schedule 47				
Single Phase	214	$18.89	$4	$6
Three Phase	2,952	$18.89	$56	$79
Schedule 49				
Single Phase	9	$20.59	$0	$0
Three Phase	1,327	$20.59	$27	$39
Schedule 83				
Single Phase	782	$42.64	$33	$47
Three Phase	12,122	$42.64	$517	$731
Schedule 85				
Secondary	1,877	$225.15	$423	$597
Primary	130	$225.15	$29	$41
Schedule 89 1-4 MW				
Secondary	110	$218.62	$24	$34
Primary	81	$218.62	$18	$25
Schedule 89 GT 4 MW				
Secondary	3	$218.62	$1	$1
Primary	32	$218.62	$7	$10
Subtransmission	10	$218.62	$2	$3
Schedule 91	207	$220.58	$46	$65
Schedule 92/94	17	$207.94	$4	$5
Schedule 93	23	$18.22	$0	$1
TOTAL	832,108		$19,561	$27,649
			TARGET	$27,649
		EQUAL PERCENT		141%

PORTLAND GENERAL ELECTRIC
ALLOCATION OF CONSUMER REVENUE REQUIREMENT
2011

Grouping	Customers	Marginal Unit Cost $ per Customer	Marginal Cost Revenues	Class Revenue Requirement
Schedule 7				
Single Phase	723,564	$30.20	$21,852	$46,143
Three Phase	67	$30.20	$2	$4
Schedule 15				
Residential	882	$18.93	$17	$35
Commercial	1,372	$10.61	$15	$31
Schedule 32				
Single Phase	53,535	$22.42	$1,200	$2,534
Three Phase	32,431	$22.42	$727	$1,535
Schedule 38				
Single Phase	46	$86.67	$4	$8
Three Phase	317	$86.67	$27	$58
Schedule 47				
Single Phase	214	$18.69	$4	$8
Three Phase	2,952	$18.69	$55	$117
Schedule 49				
Single Phase	9	$19.43	$0	$0
Three Phase	1,327	$19.43	$26	$54
Schedule 83				
Single Phase	782	$59.01	$46	$97
Three Phase	10,245	$59.01	$605	$1,277
Schedule 85				
Secondary	1,877	$1,139.13	$2,138	$4,514
Primary	130	$1,139.13	$148	$312
Schedule 89 1-4 MW				
Secondary	110	$5,334.33	$588	$1,241
Primary	81	$5,334.33	$433	$913
Schedule 89 GT 4 MW				
Secondary	3	$5,334.33	$16	$34
Primary	32	$5,334.33	$171	$360
Subtransmission	10	$5,334.33	$53	$113
Schedule 91	207	$645.12	$134	$282
Schedule 92/94	17	$614.25	$10	$22
Schedule 93	23	$39.77	$1	$2
TOTAL	830,231		$28,270	$59,696
			TARGET	$59,696
		EQUAL PERCENT		211%

TABLE 1
PORTLAND GENERAL ELECTRIC
MARGINAL COST STUDY
GROWTH AND RELIABILITY-RELATED SUBTRANSMISSION
INVESTMENTS ON A PER UNIT BASIS
2011 DOLLARS

LINE NO.	YEAR	NOMINAL SUBTRANS INVESTMENT	INDEX	ANNUAL SUBTRANS INVESTMENT 2011 $
		(A)	(B)	(C)
1	2010	$981,640	99.1%	$990,137
2	2011	$4,846,357	100.0%	$4,846,357
3	2012	$3,523,268	101.2%	$3,482,228
4	2013	$850,000	102.5%	$828,884
5	2014	$800,000	103.7%	$771,273

LINE NO.	TOTAL FIVE-YEAR INVESTMENTS	ECONOMIC CARRYING CHARGE	ANNUAL INCREMENTAL CAPITAL COST DOLLARS	DIVIDE BY GROWTH IN SYSTEM PEAK (1)	DEMAND-RELATED ANNUAL INCREMENTAL CAPITAL COST	
	(D)	(E)	(F) (D)*(E)	(G)	(H) (F)/(G)/1000	
6	$10,918,878	0.0920	$1,004,537	144	$7.00	PER KW

(1) PEAK IS NCP IN MW.

TABLE 2
PORTLAND GENERAL ELECTRIC
MARGINAL COST STUDY
GROWTH-RELATED SUBSTATION
INVESTMENTS ON A PER UNIT BASIS
2011 DOLLARS

LINE NO.	YEAR	NOMINAL SUBSTATION INVESTMENT	INDEX	ANNUAL SUBTRANS SUBSTATION 2009 $
		(A)	(B)	(C)
1	2010	$3,263,131	99.1%	$3,291,376
2	2011	$8,328,098	100.0%	$8,328,098
3	2012	$3,000,000	101.2%	$2,965,055
4	2013	$1,500,000	102.5%	$1,462,736
5	2014	$1,000,000	103.7%	$964,092

LINE NO.	TOTAL FIVE-YEAR INVESTMENTS	ECONOMIC CARRYING CHARGE	ANNUAL INCREMENTAL CAPITAL COST DOLLARS	DIVIDE BY GROWTH IN SYSTEM PEAK (1)	DEMAND-RELATED ANNUAL INCREMENTAL CAPITAL COST	
	(D)	(E)	(F) (D)*(E)	(G)	(H) (F)/(G)/1000	
6	$17,011,356	0.0853	$1,451,069	129	$11.29	PER KW

(1) PEAK IS NCP IN MW FOR CUSTOMERS AT PRIMARY AND SECONDARY DELIVERY VOLTAGE.

TABLE 3
PORTLAND GENERAL ELECTRIC
MARGINAL COST STUDY
MARGINAL COST OF DISTRIBUTION FEEDERS

Schedule	Mainline Costs	NCP	Cost per NCP	Carrying Charge	Annualized Mainline
07	$312,631,232	1,909,648	$163.71	9.20%	$15.06
32	$56,355,107	295,302	$190.84	9.20%	$17.56
38	$3,641,259	15,904	$228.95	9.20%	$21.06
47	$7,975,511	15,289	$521.66	9.20%	$47.99
49	$26,118,131	47,895	$545.32	9.20%	$50.17
83	$75,190,361	454,359	$165.49	9.20%	$15.22
85	$74,212,134	505,253	$146.88	9.20%	$13.51
89	$26,444,631	190,414	$138.88	9.20%	$12.78
Total	$582,568,366	3,434,063	$169.64	9.20%	$15.61

Schedule	Tapline Costs	Design Demand	Cost per kW Design	Carrying Charge	Annualized Tapline
07	$317,953,348	2,728,068	$116.55	9.20%	$10.72
32-1P	$41,955,563	255,045	$164.50	9.20%	$15.13
32-3P	$22,216,113	335,559	$66.21	9.20%	$6.09
38-1P	$259,033	1,904	$136.06	9.20%	$12.52
38-3P	$2,392,988	26,762	$89.42	9.20%	$8.23
47-1P	$700,106	1,909	$366.70	9.20%	$33.74
47-3P	$4,847,549	24,928	$194.46	9.20%	$17.89
49-1P	$105,002	331	$317.13	9.20%	$29.18
49-3P	$15,816,893	81,258	$194.65	9.20%	$17.91
83-1P	$4,108,611	30,967	$132.68	9.20%	$12.21
83-3P	$37,871,526	613,285	$61.75	9.20%	$5.68
85	$34,817,837	653,258	$53.30	9.20%	$4.90
89	$7,993,693	233,204	$34.28	9.20%	$3.15
Total	$491,038,262	4,986,479	$98.47	9.20%	$9.06
Total 1-P	$365,081,664	3,018,224	$120.96	9.20%	$11.13
Total 3-P	$125,956,598	1,968,254	$63.99	9.20%	$5.89

Note: use average of marginal costs for lighting schedules

Typical Industrial Feeder Cost

Distance from Substation 1000'	10.8	(includes redundant feeder)
Feeder Cost per 1000'	$46,168	
Cost per Customer	$498,618	
Carrying Charge	9.20%	
Annualized Cost	$45,873	

TABLE 4
PORTLAND GENERAL ELECTRIC
MARGINAL COST STUDY
SUMMARY OF SERVICE & TRANSFORMER COSTS

Grouping	Loaded Trans. & Service (2009 Dollars) (1)	Inflation Rate (2)	Loaded Connect Costs (2011 Dollars)	Carrying Charge	Annualized Costs
Schedule 7					
Single phase	$865.78	100.3%	$868.23	8.95%	$77.71
Three phase	LEA		$1,514.00	8.95%	$135.50
Schedule 15	$16.22	100.3%	$16.26	8.95%	$1.46
Schedule 32					
Single phase	$1,304.87	100.3%	$1,308.57	8.95%	$117.12
Three phase	$2,827.29	100.3%	$2,835.30	8.95%	$253.76
Schedule 38					
Single phase	LEA	100.3%	$2,627.28	8.95%	$235.14
Three phase	LEA	100.3%	$6,298.37	8.95%	$563.70
Schedule 47					
Single phase	LEA		$472.83	8.95%	$42.32
Three phase	LEA		$846.09	8.95%	$75.72
Schedule 49					
Single phase	LEA		$1,317.89	8.95%	$117.95
Three phase	LEA		$2,600.11	8.95%	$232.71
Schedule 83					
Single phase	$4,586.82	100.3%	$4,599.81	8.95%	$411.68
Three phase	$11,763.69	100.3%	$11,796.99	8.95%	$1,055.83
Schedule 85	$18,632.30	100.3%	$18,685.05	8.95%	$1,672.31
Schedule 89 1-4 MW	$49,286.13	100.3%	$49,425.66	8.95%	$4,423.60
Schedule 89 GT 4 MW	$262,961.99	100.3%	$263,706.46	8.95%	$23,601.73
Primary Voltage					
Schedule 85	$7,824.95	100.3%	$7,847.10	8.95%	$702.32
Schedule 89 1-4 MW	$9,328.66	100.3%	$9,355.07	8.95%	$837.28
Schedule 89 GT 4 MW	$27,412.59	100.3%	$27,490.20	8.95%	$2,460.37
Schedule 91	$10.20	100.3%	$10.23	8.95%	$0.92
Schedule 92	LEA		$149.35	8.95%	$13.37
Schedule 93	LEA		$1,250.50	8.95%	$111.92

Notes:
(1) From Job Estimate Sheets Service & Design Consultants
(2) Global Insight Producer Goods 2009 to 2011
(3) Schedule 91 figure is for shared transformer only

TABLE 5
PORTLAND GENERAL ELECTRIC
MARGINAL COST STUDY
CAPITAL COST OF INSTALLED METERS

Customer Schedule	Meter Type	Meter Cost	Installation Labor (Loaded)	Additional Materials Cost	Installed Cost (2011 $)	Customer Weighting	Weighted Average Meter Cost (2011 $)	Annual Carrying Charge	Annualized Cost
Residential									
Single phase	Radio 2S w remote connect	$163.00	$28.20	$0.00	$191.74	24.69%			
Single phase	Radio 2S w/o remote connect	$68.00	$28.20	$0.00	$96.47	75.31%	$119.99	12.53%	$15.04
Three phase	Radio 3P SC	$283.00	$42.31	$0.00	$326.23	100.00%	$326.23	12.53%	$40.88
Schedule 32									
Single phase	Radio 2S w/o remote connect	$68.00	$28.20	$0.00	$96.47	84.50%			
Single phase	Radio 1S	$82.90	$28.20	$0.00	$111.41	1.40%			
Single phase	Radio 12S	$262.00	$28.20	$0.00	$291.02	14.10%	$124.11	12.53%	$15.55
Three phase	Radio 3P SC	$283.00	$42.31	$0.00	$326.23	72.40%			
Three phase	Radio 3P CT	$283.00	$141.02	$285.00	$711.03	27.60%	$432.43	12.53%	$54.18
Schedule 38									
Single phase	Radio 12S	$262.00	$28.20	$0.00	$291.02	100.00%	$291.02	12.53%	$36.47
Three phase	Radio 3P SC	$283.00	$42.31	$0.00	$326.23	66.70%			
Three phase	Radio 3P CT	$283.00	$141.02	$285.00	$711.03	33.30%	$454.37	12.53%	$56.93
Schedule 47									
Single phase	Radio 12S	$262.00	$28.20	$0.00	$291.02	100.00%	$291.02	12.53%	$36.47
Three phase	Radio 3P SC	$283.00	$42.31	$0.00	$326.23	83.00%			
Three phase	Radio 3P CT	$283.00	$141.02	$285.00	$711.03	17.00%	$391.65	12.53%	$49.07
Schedule 49									
Single phase	Radio 12S	$262.00	$28.20	$0.00	$291.02	100.00%	$291.02	12.53%	$36.47
Three phase	Radio 3P SC	$283.00	$42.31	$0.00	$326.23	13.00%			
Three phase	Radio 3P CT	$283.00	$141.02	$285.00	$711.03	87.00%	$661.00	12.53%	$82.82
Schedule 83	**Secondary Voltage**								
Single phase	Radio 12S	$262.00	$28.20	$0.00	$291.02	100.00%	$291.02	12.53%	$36.47
Three phase	Radio 3P SC	$283.00	$42.31	$0.00	$326.23	80.00%			
Three phase	Radio 3P CT	$283.00	$141.02	$285.00	$711.03	20.00%	$403.19	12.53%	$50.52
Schedule 85	**Secondary Voltage**								
Three phase	Radio 3P CT	$377.00	$141.02	$363.00	$883.51	100.00%	$883.51	12.53%	$110.70
Schedule 89 1-4 MW									
Three phase	Radio 3P CT	$377.00	$141.02	$ 441.00	$961.74	100.00%	$961.74	12.53%	$120.51
Schedule 89 GT 4 MW									
Three phase	Radio 3P CT	$377.00	$141.02	$ 441.00	$961.74	100.00%	$961.74	12.53%	$120.51
Primary Voltage									
Schedule 85	Radio 3P CT	$377.00	$451.27	$4,308.00	$5,150.81	100.00%	$5,150.81	12.53%	$645.40
Schedule 89 1-4 MW	Radio 3P CT	$377.00	$451.27	$4,308.00	$5,150.81	100.00%	$5,150.81	12.53%	$645.40
Schedule 89 GT 4 MW	Radio 3P CT	$377.00	$451.27	$4,308.00	$5,150.81	100.00%	$5,150.81	12.53%	$645.40
Subtrans. Voltage	Radio 3P CT	$7,254	$40,477.53	$48,059.53	$96,062.42	100.00%	$96,062.42	12.53%	$12,036.62
Schedule 93									
Three phase	Radio 3P CT	$ 283.00	$ 902.64	$ 6,564.00	$7,771.58	100.00%	$7,771.58	12.53%	$973.78

TABLE 6
PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION O&M

Allocation of Substation O&M

Schedule	Marginal Capital Cost $/kW	Usages	Annualized Capital Cost	Allocated O&M	Marginal Unit Cost $/kW
Schedule 7	$11.29	2,027,780	$22,893,636	$3,802,146	$13.17
Schedule 15	$11.29	6,358	$71,782	$11,921	$13.17
Schedule 32	$11.29	316,756	$3,576,175	$593,927	$13.17
Schedule 38	$11.29	23,032	$260,031	$43,186	$13.17
Schedule 47	$11.29	14,608	$164,924	$27,390	$13.17
Schedule 49	$11.29	45,344	$511,934	$85,021	$13.17
Schedule 83	$11.29	533,485	$6,023,046	$1,000,300	$13.17
Schedule 85	$11.29	580,135	$6,549,724	$1,087,770	$13.17
Schedule 89 1-4 MW	$11.29	230,414	$2,601,374	$432,033	$13.17
Schedule 89 GT 4 MW	$11.29	287,582	$3,246,801	$539,225	$13.17
Schedule 91	$11.29	28,658	$323,549	$53,735	$13.17
Schedules 92 & 94	$11.29	567	$6,401	$1,063	$13.17
Schedule 93	$11.29	595	$6,718	$1,116	$13.17
Totals		4,095,314	$46,236,095	$7,678,833	
FERC Accounts 582 & 592 Test Period O&M			$7,678,833		

Allocation of Meters O&M

Schedule	Marginal Capital Cost	Average Customers	Annualized Capital Cost	Allocated O&M	Marginal Unit Cost
Schedule 7					
Single-phase	$15.04	723,564	$10,882,396	$1,594,290	$17.24
Three-phase	$40.88	67	$2,739	$401	$46.87
Schedule 15		2,254			
Schedule 32					
Single-phase	$15.55	53,535	$832,465	$121,958	$17.83
Three-phase	$54.18	32,431	$1,757,116	$257,421	$62.12
Schedule 38					
Single-phase	$36.47	46	$1,662	$244	$41.81
Three-phase	$56.93	317	$18,023	$2,640	$65.27
Schedule 47					
Single-phase	$36.47	214	$7,805	$1,143	$41.81
Three-phase	$49.07	2,952	$144,855	$21,221	$56.26
Schedule 49					
Single-phase	$36.47	9	$328	$48	$41.81
Three-phase	$82.82	1,327	$109,902	$16,101	$94.95
Schedule 83 S					
Single-phase	$36.47	782	$28,501	$4,175	$41.81
Three-phase	$50.52	10,245	$517,586	$75,827	$57.92
Schedule 85 S	$110.70	1,877	$207,747	$30,435	$126.92
Schedule 89 S 1-4 MW	$120.51	110	$13,296	$1,948	$138.16
Schedule 89 S GT 4 MW	$120.51	3	$362	$53	$138.16
Schedule 85 P	$645.40	130	$83,741	$12,268	$739.95
Schedule 89 P 1-4 MW	$645.40	81	$52,439	$7,682	$739.95
Schedule 89 P GT 4 MW	$645.40	32	$20,653	$3,026	$739.95
Schedule 89 T	$12,036.62	10	$120,366	$17,634	$13,800.01
Schedule 91		207			
Schedule 92/94		17			
Schedule 93	$973.78	23	$22,397	$3,281	$1,116.44
Totals		830,231	$14,824,379	$2,171,798	
FERC Accounts 586 & 597 Test Period O&M			$2,171,798		

Allocation of Services & Transformers O&M

Schedule	Marginal Capital Costs	Average Customers	Annualized Capital Cost	Allocated O&M	Marginal Unit Cost
Schedule 7					
Single-phase	$77.71	723,564	$56,228,126	$2,177,016	$80.72
Three-phase	$135.50	67	$9,079	$351	$140.75
Schedule 15 lights	$1.46	21,851	$31,902	$1,235	$1.52
Schedule 32					
Single-phase	$117.12	53,535	$6,269,990	$242,759	$121.65
Three-phase	$253.76	32,431	$8,229,712	$318,634	$263.58
Schedule 38					
Single-phase	$235.14	46	$10,718	$415	$244.24
Three-phase	$563.70	317	$178,458	$6,909	$585.53
Schedule 47					
Single-phase	$42.32	214	$9,056	$351	$43.96
Three-phase	$75.72	2,952	$223,525	$8,654	$78.65
Schedule 49					
Single-phase	$117.95	9	$1,062	$41	$122.52
Three-phase	$232.71	1,327	$308,806	$11,956	$241.72
Schedule 83 S					
Single-phase	$411.68	782	$321,728	$12,457	$427.62
Three-phase	$1,055.83	10,245	$10,817,154	$418,814	$1,096.71
Schedule 85 S	$1,672.31	1,877	$3,138,368	$121,510	$1,737.06
Schedule 89 S 1-4 MW	$4,423.60	110	$488,071	$18,897	$4,594.87
Schedule 89 S GT 4 MW	$23,601.73	3	$70,805	$2,741	$24,515.53
Schedule 85 P	$702.32	130	$91,126	$3,528	$729.51
Schedule 89 P 1-4 MW	$837.28	81	$68,029	$2,634	$869.70
Schedule 89 P GT 4 MW	$2,460.37	32	$78,732	$3,048	$2,555.63
Schedule 91 lights	$0.92	156,566	$144,041	$5,577	$0.96
Schedule 92 intersections	$13.37	1,663	$22,234	$861	$13.89
Schedule 93	$111.92	23	$2,574	$100	$116.25
Totals		1,007,823	$86,743,297	$3,358,490	
Service & Transformer O&M			$3,358,490		

Allocation of Backbone Feeder O&M

Schedule	Backbone Feeder Cost	Usage	Annualized Capital Cost	Allocated O&M	Marginal Unit Cost
Schedule 7					
Single-phase	$15.06	2,027,592	$30,535,539	$15,393,007	$22.65
Three-phase	$15.06	188	$2,828	$1,425	$22.65
Schedule 15	$15.61	6,358	$99,248	$50,031	$23.48
Schedule 32					
Single-phase	$17.56	133,472	$2,343,769	$1,181,497	$26.41
Three-phase	$17.56	183,284	$3,218,466	$1,622,433	$26.41
Schedule 38					
Single-phase	$21.06	1,305	$27,482	$13,854	$31.68
Three-phase	$21.06	21,727	$457,571	$230,662	$31.68
Schedule 47					
Single-phase	$47.99	569	$27,295	$13,759	$72.18
Three-phase	$47.99	14,039	$673,743	$339,635	$72.18
Schedule 49					
Single-phase	$50.17	155	$7,793	$3,929	$75.46
Three-phase	$50.17	45,189	$2,267,115	$1,142,856	$75.46
Schedule 83					
Single-phase	$15.22	21,593	$328,638	$165,667	$22.89
Three-phase	$15.22	511,892	$7,791,004	$3,927,456	$22.89
Schedule 85	$13.51	580,135	$7,837,624	$3,950,957	$20.32
Schedule 89 1-4 MW	$12.78	230,414	$2,944,691	$1,484,423	$19.22
Schedule 89 GT 4 MW	$45,873	32	$1,467,936	$739,989	$68,998
Schedule 89 T	$51,962	10	$519,620	$261,941	$78,156
Schedule 91	$15.61	28,658	$447,351	$225,510	$23.48
Schedule 92	$15.61	567	$8,851	$4,462	$23.48
Schedule 93	$15.61	595	$9,288	$4,682	$23.48
Totals			$61,015,854	$30,758,175	
Feeder Backbone O&M			$30,758,175		

Allocation of Feeder Local Facilities O&M

Schedule	Local Facilities Cost	Usage	Annualized Capital Cost	Allocated O&M	Marginal Unit Cost
Schedule 7					
Single-phase	$10.72	2,894,254	$31,026,406	$15,640,454	$16.12
Three-phase	$10.72	268	$2,873	$1,448	$16.12
Schedule 15	$11.13	6,358	$70,765	$35,673	$16.74
Schedule 32					
Single-phase	$15.13	267,674	$4,049,904	$2,041,562	$22.76
Three-phase	$6.09	369,714	$2,251,560	$1,135,015	$9.16
Schedule 38					
Single-phase	$12.52	2,284	$28,592	$14,413	$18.83
Three-phase	$8.23	39,225	$322,819	$162,734	$12.38
Schedule 47					
Single-phase	$33.74	1,584	$53,431	$26,934	$50.75
Three-phase	$17.89	24,206	$433,052	$218,302	$26.91
Schedule 49					
Single-phase	$29.18	426	$12,422	$6,262	$43.89
Three-phase	$17.91	76,966	$1,378,461	$694,884	$26.94
Schedule 83					
Single-phase	$12.21	30,557	$373,097	$188,079	$18.37
Three-phase	$5.68	726,382	$4,125,852	$2,079,847	$8.54
Schedule 85	$4.90	759,830	$3,723,167	$1,876,854	$7.37
Schedule 89 1-4 MW	$3.15	285,896	$900,573	$453,980	$4.74
Schedule 89 GT 4 MW					
Schedule 91	$11.13	28,658	$318,964	$160,790	$16.74
Schedule 92	$5.89	567	$3,340	$1,684	$8.86
Schedule 93	$5.89	2,093	$12,328	$6,214	$8.86
Totals			$49,087,605	$24,745,128	
Feeder Local Facilities O&M			$24,745,128		

Allocation of Subtransmission O&M

Schedule	Marginal Inv. Cost $/kW	Usages	Annualized Capital Cost	Allocated O&M	Marginal Unit Cost $/kW
Schedule 7	$7.00	2,054,344	$14,380,408	$5,502,734	$9.68
Schedule 15	$7.00	6,442	$45,094	$17,255	$9.68
Schedule 32	$7.00	320,905	$2,246,335	$859,571	$9.68
Schedule 38	$7.00	23,333	$163,331	$62,499	$9.68
Schedule 47	$7.00	14,800	$103,600	$39,643	$9.68
Schedule 49	$7.00	45,938	$321,566	$123,049	$9.68
Schedule 83	$7.00	540,474	$3,783,318	$1,447,705	$9.68
Schedule 85	$7.00	587,734	$4,114,138	$1,574,295	$9.68
Schedule 89 1-4 MW	$7.00	233,432	$1,634,024	$625,267	$9.68
Schedule 89 GT 4 MW	$7.00	423,179	$2,962,253	$1,133,521	$9.68
Schedule 91	$7.00	29,034	$203,238	$77,770	$9.68
Schedule 92	$7.00	575	$4,025	$1,540	$9.68
Schedule 93	$7.00	603	$4,221	$1,615	$9.68
Totals		4,280,793	$29,965,551	$11,466,466	
Subtransmission O&M			$11,466,466		

FERC Account	O&M	Allocated	Total	Category
582 & 592	$5,252,722	$2,426,111	$7,678,833	Substations
586 & 597	$1,485,623	$686,175	$2,171,798	Meters
583, 584, 593-595	$7,843,661	$3,622,806	$11,466,466	115 kV
583, 584, 593-595	$37,967,153	$17,536,150	$55,503,303	13 kV
583, 584, 593-595	$2,297,382	$1,061,108	$3,358,490	Transformers & Service
Subtotal	$54,846,540	$25,332,349	$80,178,889	

TABLE 7
PORTLAND GENERAL ELECTRIC
2011 MARGINAL COST STUDY
SUMMARY OF CONSUMER SERVICE MARGINAL COSTS

SCHEDULE	ANNUAL METERING EXPENSES	ANNUAL BILLING EXPENSES	ANNUAL OTHER CONSUMER EXPENSES	TOTAL CONSUMER EXPENSES
Schedule 7 Residential	$2.89	$22.60	$30.20	$55.69
Schedule 15 Residential	$0.00	$10.13	$18.93	$29.06
Schedule 15 Commercial	$0.00	$11.35	$10.61	$21.96
Schedule 32 General Service	$8.57	$23.11	$22.42	$54.10
Schedule 38 GS TOU	$9.28	$15.07	$86.67	$111.02
Schedule 47 Irrigation	$9.73	$18.89	$18.69	$47.31
Schedule 49 Irrigation	$10.47	$20.59	$19.43	$50.49
Schedule 83 General Service	$9.00	$42.64	$59.01	$110.65
Schedule 85 General Service	$9.01	$225.15	$1,139.13	$1,373.29
Schedule 89 General Service	$8.35	$218.62	$5,334.33	$5,561.30
Schedule 91 Streetlighting	$0.00	$220.58	$645.12	$865.70
Schedule 92 / 94 Traffic Sign. & Comm. Dev.	$0.00	$207.94	$614.25	$822.19
Schedule 93 Field Lighting	$9.19	$18.22	$39.77	$67.18

TABLE 8
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
Schedule 7 Residential							
Single-phase	$9.68	$13.17	$22.65	$16.12	$80.72	$17.24	$55.69
Three-phase	$9.68	$13.17	$22.65	$16.12	$140.75	$46.87	$55.69
Schedule 15 Residential	$9.68	$13.17	$23.48	$16.74	$1.52	N/A	$29.06
Schedule 15 Commercial	$9.68	$13.17	$23.48	$16.74	$1.52	N/A	$21.96
Schedule 32 General Service							
Single-phase	$9.68	$13.17	$26.41	$22.76	$121.65	$17.83	$54.10
Three-phase	$9.68	$13.17	$26.41	$9.16	$263.58	$62.12	$54.10
Schedule 38 TOU							
Single-phase	$9.68	$13.17	$31.68	$18.83	$244.24	$41.81	$111.02
Three-phase	$9.68	$13.17	$31.68	$12.38	$585.53	$65.27	$111.02
Schedule 47 Irrigation							
Single-phase	$9.68	$13.17	$72.18	$50.75	$43.96	$41.81	$47.31
Three-phase	$9.68	$13.17	$72.18	$26.91	$78.65	$56.26	$47.31
Schedule 49 Irrigation							
Single-phase	$9.68	$13.17	$75.46	$43.89	$122.52	$41.81	$50.49
Three-phase	$9.68	$13.17	$75.46	$26.94	$241.72	$94.95	$50.49
Schedule 83 Secondary General Service							
Single-phase	$9.68	$13.17	$22.89	$18.37	$427.62	$41.81	$110.65
Three-phase	$9.68	$13.17	$22.89	$8.54	$1,096.71	$57.92	$110.65
Schedule 85 Secondary General Service	$9.68	$13.17	$20.32	$7.37	$1,737.06	$126.92	$1,373.29
Schedule 85 Primary General Service	$9.68	$13.17	$20.32	$7.37	$729.51	$739.95	$1,373.29
Schedule 89 Secondary 1-4 MW	$9.68	$13.17	$19.22	$4.74	$4,594.87	$138.16	$5,561.30
Schedule 89 Primary 1-4 MW	$9.68	$13.17	$19.22	$4.74	$869.70	$739.95	$5,561.30
Schedule 89 Secondary GT 4 MW	$9.68	$13.17	$68,998	N/A	$24,515.53	$138.16	$5,561.30
Schedule 89 Primary GT 4 MW	$9.68	$13.17	$68,998	N/A	$2,555.63	$739.95	$5,561.30
Schedule 89 Subtransmission	$9.68	N/A	$78,156.00	N/A	N/A	$13,800.01	$5,561.30
Schedule 91 Streetlighting	$9.68	$13.17	$23.48	$16.74	$0.96	N/A	$865.70
Schedules 92 & 94 Traffic Signals & Comm. Devices	$9.68	$13.17	$23.48	$8.86	$13.89	N/A	$822.19
Schedule 93 Field Lighting	$9.68	$13.17	$23.48	$8.86	$116.25	$1,116.44	$67.18

PORTLAND GENERAL ELECTRIC

PROPOSED
Summary of Area and Streetlighting Revenue

Schedule 15 - Area Lighting	
Fixtures,Circuits & Maintenance	$1,568,944
Poles	$767,165
Energy (volumetric c/kWh rate)	$2,269,403
Total	**$4,605,512**

Schedule 91 - Street and Highway Lighting	
Fixtures, Circuits & Maintenance (Options A&B)	$5,943,028
Poles (Options A&B)	$2,271,615
Circuit Charge for Option C lights	$41,532
Energy (volumetric c/kWh rate)	$10,229,620
Total	**$18,485,796**

PORTLAND GENERAL ELECTRIC
Schedule 91, Proposed Prices, Counts and Revenue

Lum CODE	Light Description	Type	Watts	Monthly kWh	Category	Tariff Rates A	Tariff Rates B	Monthly Energy	Proposed Sch 91 A&B Counts A	B	C	TOTAL	Annual MWh	Annual Fixed Revenue A	B	Annual Energy
84	Cobrahead - PD	HPS	100-watt	43	Standard	*	$2.56	$4.04	-	28,381	926	29,307	15,122	*	$871,864	$1,420,803
85	Cobrahead - PD	HPS	150-watt	62	Standard	*	$2.57	$5.82	-	1,751	507	2,258	1,680	*	$54,001	$157,699
89	Cobrahead - PD	HPS	200-watt	79	Standard	*	$2.61	$7.42	-	5,350	291	5,641	5,348	*	$167,562	$502,275
86	Cobrahead - PD	HPS	250-watt	102	Standard	*	$2.61	$9.58	-	2,409	947	3,356	4,108	*	$75,450	$385,806
87	Cobrahead - PD	HPS	400-watt	163	Standard	*	$2.62	$15.30	-	1,841	66	1,907	3,730	*	$57,881	$350,125
34	Cobrahead	HPS	100-watt	43	Standard	$5.23	$2.75	$4.04	18,400	16,231	756	35,387	18,260	$1,154,784	$535,623	$1,715,562
35	Cobrahead	HPS	150-watt	62	Standard	$5.25	$2.76	$5.82	1,248	6,995	1,012	9,255	6,886	$78,624	$231,674	$646,369
39	Cobrahead	HPS	200-watt	79	Standard	$5.66	$2.80	$7.42	3,973	5,462	1,088	10,523	9,976	$269,846	$183,523	$936,968
36	Cobrahead	HPS	250-watt	102	Standard	$5.69	$2.79	$9.58	563	2,741	987	4,291	5,252	$38,442	$91,769	$493,293
37	Cobrahead	HPS	400-watt	163	Standard	$5.73	$2.83	$15.30	774	1,975	333	3,082	6,028	$53,220	$67,071	$565,855
31	Flood	HPS	250-watt	102	Standard	$6.00	$2.86	$9.58	123	2	2	127	155	$8,856	$69	$14,600
32	Flood	HPS	400-watt	163	Standard	$6.02	$2.88	$15.30	309	38	9	356	696	$22,322	$1,313	$65,362
40	Post-Top	HPS	100-watt	43	Standard	$5.71	$2.83	$4.04	4,592	4,036	853	9,481	4,892	$314,644	$137,063	$459,639
76	Shoebox	HPS	70-watt	30	Standard	$5.84	$2.82	$2.82	109	164	1	274	99	$7,639	$5,550	$9,272
77	Shoebox	HPS	100-watt	43	Standard	$6.11	$2.90	$4.04	2,481	6,413	2,144	11,038	5,696	$181,907	$223,172	$535,122
78	Shoebox	HPS	150-watt	62	Standard	$6.36	$2.91	$5.82	207	431	125	763	568	$15,798	$15,051	$53,288
81	Special Acorn	HPS	100-watt	43	Custom	$8.74	$3.23	$4.04	653	4,218	467	5,338	2,754	$68,487	$163,490	$258,786
12	Acorn - Indep.	HPS	100-watt	43	Custom	$8.16	$3.24	$4.04	3	2	-	5	3	$294	$78	$242
13	Acorn - Indep.	HPS	150-watt	62	Custom	$8.17	$3.25	$5.82	-	-	-	0	0	$0	$0	$0
64	Capitol Acorn	HPS	100-watt	43	Custom	$12.05	$3.34	$4.04	-	9	-	9	5	$0	$361	$436
67	Capitol Acorn	HPS	150-watt	62	Custom	$12.06	$3.35	$5.82	-	372	-	372	277	$0	$14,954	$25,980
65	Capitol Acorn	HPS	200-watt	79	Custom	$12.06	$3.35	$7.42	-	57	-	57	54	$0	$2,291	$5,075
66	Capitol Acorn	HPS	250-watt	102	Custom	$12.06	$3.35	$9.58	-	-	-	0	0	$0	$0	$0
82	Victorian	HPS	150-watt	62	Custom	$8.48	$3.23	$5.82	22	1,485	196	1,703	1,267	$2,239	$57,559	$118,938
49	Victorian	HPS	200-watt	79	Custom	$8.61	$3.32	$7.42	3	106	9	118	112	$310	$4,223	$10,507
83	Victorian	HPS	250-watt	102	Custom	$8.69	$3.32	$9.58	72	1,214	3	1,289	1,578	$7,508	$48,366	$148,183
98	Techtra	HPS	100-watt	43	Custom	$15.13	$4.21	$4.04	565	38	-	603	311	$102,581	$1,920	$29,233
99	Techtra	HPS	150-watt	62	Custom	$15.14	$4.22	$5.82	5	-	-	5	4	$908	$0	$349
88	Techtra	HPS	250-watt	102	Custom	$21.16	$4.82	$9.58	-	128	-	128	157	$0	$7,404	$14,715
96	KIM Archetype	HPS	250-watt	102	Custom	*	$3.33	$9.58	-	65	23	88	108	*	$2,597	$10,116
97	KIM Archetype	HPS	400-watt	163	Custom	*	$3.32	$15.30	-	20	28	48	94	*	$797	$8,813
90	Westbrooke Acorn	HPS	70-watt	30	Custom	$13.00	$3.40	$2.82	-	18	-	18	6	$0	$734	$609
91	Westbrooke Acorn	HPS	100-watt	43	Custom	$12.96	$3.39	$4.04	-	-	-	0	0	$0	$0	$0
92	Westbrooke Acorn	HPS	150-watt	62	Custom	$12.97	$3.40	$5.82	-	2	-	2	1	$0	$82	$140
93	Westbrooke Acorn	HPS	200-watt	79	Custom	$13.11	$3.40	$7.42	-	2	-	2	2	$0	$82	$178
94	Westbrooke Acorn	HPS	250-watt	102	Custom	$13.11	$3.40	$9.58	-	14	-	14	17	$0	$571	$1,609
48	Cobrahead	MH	175-watt	71	Custom	$5.50	$2.95	$6.67	3	3	62	68	58	$198	$106	$5,443
60	Flood	MH	400-watt	156	Custom	$6.02	$3.00	$14.65	17	1	-	18	34	$1,228	$36	$3,164
47	Flood	HPS	750-watt	285	Custom	$8.33	$3.92	$26.76	50	-	-	50	171	$4,998	$0	$16,056
9	Mongoose	HPS	150-watt	62	Custom	$7.27	$3.00	$5.82	-	13	-	13	10	$0	$468	$908
10	Mongoose	HPS	250-watt	102	Custom	$7.36	$3.01	$9.58	2	-	-	2	2	$177	$0	$230
11	Mongoose	HPS	400-watt	163	Custom	$7.40	$3.03	$15.30	-	-	-	0	0	$0	$0	$0
2	Victorian	QL	85-watt	32	Altern.	$10.59	$2.05	$3.00	-	11	179	190	73	$0	$271	$6,840

PORTLAND GENERAL ELECTRIC
Schedule 91, Proposed Prices, Counts and Revenue

Lum				Monthly		Tariff Rates		Monthly	Proposed Sch 91 A&B Counts				Annual	Annual Fixed Revenue		Annual
CODE	Light Description	Type	Watts	kWh	Category	A	B	Energy	A	B	C	TOTAL	MWh	A	B	Energy
1	Victorian	QL	165-watt	60	Altern.	$12.28	$2.13	$5.63	-	104	113	217	156	$0	$2,658	$14,661
4	Techtra	QL	85-watt	32	Altern.	$13.97	$2.18	$3.00	-	-	-	0	0	$0	$0	$0
3	Techtra	QL	165-watt	60	Altern.	$14.68	$2.22	$5.63	-	147	-	147	106	$0	$3,916	$9,931
19	Cobrahead - (C) Only	MV	100-watt	39	Obsolete	*	*	$3.66	-	-	1	1	0	*	*	$44
21	Cobrahead	MV	175-watt	66	Obsolete	$5.38	$2.71	$6.20	1,695	1,750	102	3,547	2,809	$109,429	$56,910	$263,897
22	Cobrahead	MV	250-watt	94	Obsolete	$6.29	$2.92	$8.83	2	-	23	25	28	$151	$0	$2,649
23	Cobrahead	MV	400-watt	147	Obsolete	$5.45	$2.79	$13.80	325	96	81	502	886	$21,255	$3,214	$83,131
24	Cobrahead	MV	1,000-watt	374	Obsolete	$6.23	$3.08	$35.11	16	9	5	30	135	$1,196	$333	$12,640
50	Special Box - Space-Glo	HPS	70-watt	30	Obsolete	$8.71	$2.83	$2.82	21	-	23	44	16	$2,195	$0	$1,489
46	Special Box - Space-Glo	MV	175-watt	66	Obsolete	$8.85	$2.75	$6.20	19	138	47	204	162	$2,018	$4,554	$15,178
51	Box - Gardco Hub / Opt C	HPS	Twin 70-watt	60	Obsolete	*	*	$5.63	-	-	43	43	31	*	*	$2,905
52	Box - Gardco Hub / Opt C	HPS	70-watt	30	Obsolete	*	*	$2.82	-	-	40	40	14	*	*	$1,354
53	Box - Gardco Hub	HPS	100-watt	43	Obsolete	$8.50	$3.15	$4.04	-	5	15	20	10	$0	$189	$970
54	Box - Gardco Hub	HPS	150-watt	62	Obsolete	*	$3.16	$5.82	-	64	42	106	79	*	$2,427	$7,403
55	Box - Gardco Hub / Opt C	HPS	250-watt	102	Obsolete	*	*	$9.58	-	-	228	228	279	*	*	$26,211
56	Box - Gardco Hub / Opt C	HPS	400-watt	163	Obsolete	*	*	$15.30	-	-	111	111	217	*	*	$20,380
58	Box - Gardco Hub	MH	250-watt	99	Obsolete	*	$3.36	$9.30	-	7	26	33	39	*	$282	$3,683
59	Box - Gardco Hub	MH	400-watt	156	Obsolete	*	$3.74	$14.65	-	26	-	26	49	*	$1,167	$4,571
69	Cobrahead DW 70/100	HPS	100-watt	43	Obsolete	*	$2.73	$4.04	-	92	-	92	47	*	$3,014	$4,460
70	Cobrahead DW 100/150	HPS	100-watt	43	Obsolete	*	$2.73	$4.04	-	412	-	412	213	*	$13,497	$19,974
71	Cobrahead DW 100/150	HPS	150-watt	62	Obsolete	*	$2.74	$5.82	-	315	5	320	238	*	$10,357	$22,349
95	KIM SBC Shoebox	HPS	150-watt	62	Obsolete	*	$3.65	$5.82	-	36	66	102	76	*	$1,577	$7,124
80	Acorn Type	HPS	70-watt	30	Obsolete	$8.48	$2.83	$2.82	24	7	30	61	22	$2,442	$238	$2,064
73	GardCo Bronze - (C) Only	HPS	70-watt	30	Obsolete	*	*	$2.82	-	-	43	43	15	*	*	$1,455
72	GardCo Bronze - (C) Only	MV	175-watt	66	Obsolete	*	*	$6.20	-	-	319	319	253	*	*	$23,734
74	Acrylic Sphere - (C) Only	MV	400-watt	147	Obsolete	*	*	$13.80	-	-	4	4	7	*	*	$662
25	Post-Top - Black	HPS	70-watt	30	Obsolete	$5.09	$2.73	$2.82	1,550	1,306	40	2,896	1,043	$94,674	$42,785	$98,001
43	Rect.Type - (C) Only	HPS	200-watt	79	Obsolete	*	*	$7.42	-	-	137	137	130	*	*	$12,198
5	Incand. - (C) Only	IND	92-watt	31	Obsolete	*	*	$2.91	-	-	29	29	11	*	*	$1,013
6	Incand. - (C) Only	IND	182-watt	62	Obsolete	*	*	$5.82	-	-	7	7	5	*	*	$489
29	Post-Top	MV	175-watt	66	Obsolete	$5.48	$2.70	$6.20	118	1,221	7	1,346	1,066	$7,760	$39,560	$100,142
27	Flood	HPS	70-watt	30	Obsolete	$5.69	$2.80	$2.82	-	-	7	7	3	$0	$0	$237
30	Flood	HPS	100-watt	43	Obsolete	$5.58	$2.77	$4.04	49	7	-	56	29	$3,281	$233	$2,715
38	Flood	HPS	200-watt	79	Obsolete	$5.98	$2.84	$7.42	189	43	-	232	220	$13,563	$1,465	$20,657
33	Cobrahead	HPS	70-watt	30	Obsolete	$5.18	$2.79	$2.82	1,688	908	1,044	3,640	1,310	$104,926	$30,400	$123,178
41	Cobrahead - PD	HPS	310-watt	124	Obsolete	$6.40	$3.14	$11.64	7	21	-	28	42	$538	$791	$3,911
14	Ornamental - (C) Only	HPS	100-watt	43	Obsolete	*	*	$4.04	-	-	1,701	1,701	878	*	*	$82,464
15	Twin Ornamental -(C) Only	HPS	Twin 100-watt	86	Obsolete	*	*	$8.07	-	-	2,612	2,612	2,696	*	*	$252,946
7	Flourescent - (C) Only	FLR	28-watt	12	Obsolete	*	*	$1.13	-	-	12	12	2	*	*	$163
									---------	---------	---------	---------	---------	---------	---------	---------
							Totals		**39,877**	**98,712**	**17,977**	**156,566**	**108,913**	**$2,698,437**	**$3,244,591**	**$10,229,620**

Notes:
1. Obsolote fixtures are not available to new service
2. Option C are customer owned and maintained and only pay the respective energy charge

PORTALND GENERAL ELECTRIC

Schedule 91 Poles, Forecasted Revenue at Proposed Prices

Pole CODE	Pole Description	Material	Pole Height	Option	Tariff Rates	Counts	Annual Revenues
57	Black	Fiberglass	20	A	$4.10	2,024	$99,581
59	Bronze	Fiberglass	30	A	$5.47	2,424	$159,111
61	Gray	Fiberglass	30	A	$5.49	3,046	$200,670
1	SLO	Wood	30 to 35	A	$4.71	3,666	$207,202
3	SLO	Wood	40 to 55	A	$5.91	553	$39,219
58	Black	Fiberglass	20	B	$0.14	4,952	$8,319
60	Bronze	Fiberglass	30	B	$0.18	6,160	$13,306
62	Gray	Fiberglass	30	B	$0.18	11,205	$24,203
46	SLO	Wood	30 to 35	B	$0.15	931	$1,676
47	SLO	Wood	40 to 55	B	$0.20	181	$434
31	Regular	Aluminum	16	A	$5.83	544	$38,058
32	Regular	Aluminum	25	A	$9.48	5,415	$616,010
33	Regular	Aluminum	30	A	$10.26	241	$29,672
28	Regular	Aluminum	35	A	$11.29	76	$10,296
18	Davit	Aluminum	25	A	$9.79	72	$8,459
6	Davit	Aluminum	30	A	$10.44	410	$51,365
29	Davit	Aluminum	35	A	$11.53	182	$25,182
70	Davit with 8-foot Arm	Aluminum	40	A	$14.08	9	$1,521
27	Double Davit	Aluminum	30	A	$12.56	6	$904
65	Fluted Victorian Ornamental	Aluminum	14	A	$11.08	0	$0
69	Non-fluted Techtra Ornamental	Aluminum	18	A	$19.81	512	$121,713
66	Fluted Ornamental	Aluminum	16	A	$10.60	101	$12,847
77	Non-fluted Westbrooke	Aluminum	16	A	$15.95	111	$21,245
43	Painted Ornamental	Aluminum	35	A	$27.35	0	$0
4	Ameron Post Top	Concrete	25	A	$23.42	0	$0
63	Fluted Ornamental -Black	Fiberglass	14	A	$6.47	662	$51,398
67	Regular - Color may vary	Fiberglass	22	A	$3.17	15	$571
68	Regular - Color may vary	Fiberglass	35	A	$7.47	149	$13,356
16	Anchor Base -Gray	Fiberglass	35	A	$11.95	26	$3,728
35	Direct Bury with Shroud	Fiberglass	18	A	$6.20	6	$446
34	Regular	Aluminum	16	B	$0.20	95	$228
8	Regular	Aluminum	25	B	$0.32	1,892	$7,265
48	Regular	Aluminum	30	B	$0.34	679	$2,770
54	Regular	Aluminum	35	B	$0.38	464	$2,116
13	Davit	Aluminum	25	B	$0.33	113	$447
12	Davit	Aluminum	30	B	$0.35	1,296	$5,443
53	Davit	Aluminum	35	B	$0.38	1,820	$8,299
76	Davit with 8-foot Arm	Aluminum	40	B	$0.47	169	$953
14	Double Davit	Aluminum	30	B	$0.42	62	$312
71	Fluted Victorian Ornamental	Aluminum	14	B	$0.37	1,039	$4,613
75	Non-fluted Techtra Ornamental	Aluminum	18	B	$0.65	369	$2,878
72	Fluted Ornamental	Aluminum	16	B	$0.35	1,541	$6,472
78	Non-fluted Westbrooke	Aluminum	16	B	$0.52	69	$431
44	Painted Ornamental	Aluminum	35	B	$0.90	62	$670
5	Ameron Post Top	Concrete	25	B	$0.78	43	$402
64	Fluted Ornamental -Black	Fiberglass	14	B	$0.21	2,022	$5,095

PORTALND GENERAL ELECTRIC

Schedule 91 Poles, Forecasted Revenue at Proposed Prices

Pole CODE	Pole Description	Material	Pole Height	Option	Tariff Rates	Counts	Annual Revenues
73	Regular - Color may vary	Fiberglass	22	B	$0.11	487	$643
74	Regular - Color may vary	Fiberglass	35	B	$0.25	1,779	$5,337
17	Anchor Base -Gray	Fiberglass	35	B	$0.40	58	$278
36	Direct Bury with Shroud	Fiberglass	18	B	$0.21	545	$1,373
2	Post	Aluminum	30	A	$5.83	587	$41,067
30	Ornamental Post	Concrete	35 or less	A	$9.48	43	$4,892
37	Painted Regular	Steel	25	A	$9.48	587	$66,777
38	Painted Regular	Steel	30	A	$10.26	184	$22,654
39	Laminated without Mast Arm	Wood	20	A	$5.30	2,916	$185,458
24	Laminted SLO Pole	Wood	20	A	$4.10	339	$16,679
41	Curved laminated	Wood	30	A	$6.84	906	$74,364
11	Painted Underground	Wood	35	A	$4.71	520	$29,390
22	Painted SLO Pole	Wood	35	A	$4.71	50	$2,826
55	Bronze Alloy GardCo	Bronze	12	B	$0.24	23	$66
25	Ornamental Post	Concrete	35 or less	B	$0.32	282	$1,083
7	Painted Regular	Steel	25	B	$0.32	348	$1,336
49	Painted Regular	Steel	30	B	$0.34	40	$163
21	Unpainted with 6-foot Mast Arm	Steel	30	B	$0.34	51	$208
51	Unpainted with 6-foot Davit Arm	Steel	30	B	$0.35	36	$151
40	Unpainted with 8-foot Mast Arm	Steel	35	B	$0.38	119	$543
42	Unpainted with 8-foot Davit Arm	Steel	35	B	$0.38	17	$78
23	Laminated without Mast Arm	Wood	20	B	$0.14	2,403	$4,037
45	Curved laminated	Wood	30	B	$0.25	144	$432
26	Painted Underground	Wood	35	B	$0.20	1,204	$2,890

Total Option As	26,382	$2,156,662
Total Option Bs	42,700	$114,953
	69,082	$2,271,615

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	$5.69	$6.20	$11.89	3,117	2,469	$212,828	$231,904	$444,732
23	Cobrahead	MV	400-watt	147	$5.76	$13.80	$19.56	2,944	5,194	$203,515	$487,587	$691,102
24	Cobrahead	MV	1000-watt	374	$6.60	$35.11	$41.71	126	564	$9,946	$52,910	$62,856
33	Cobrahead - (non-pd)	HPS	70-watt	30	$5.46	$2.82	$8.28	1,238	446	$81,114	$41,894	$123,008
34	Cobrahead - (non-pd)	HPS	100-watt	43	$5.51	$4.04	$9.55	3,413	1,761	$225,673	$165,467	$391,140
35	Cobrahead - (non-pd)	HPS	150-watt	62	$5.54	$5.82	$11.36	998	743	$66,353	$69,707	$136,059
39	Cobrahead - (non-pd)	HPS	200-watt	79	$5.99	$7.42	$13.41	1,793	1,700	$128,916	$159,693	$288,609
36	Cobrahead - (non-pd)	HPS	250-watt	102	$6.02	$9.58	$15.60	742	909	$53,632	$85,348	$138,981
41	Cobrahead - (PD)	HPS	310-watt	124	$6.77	$11.64	$18.41	6	9	$487	$838	$1,326
37	Cobrahead - (non-pd)	HPS	400-watt	163	$6.07	$15.30	$21.37	1,605	3,139	$116,910	$294,682	$411,592
30	Flood	HPS	100-watt	43	$5.90	$4.04	$9.94	745	384	$52,753	$36,123	$88,876
38	Flood	HPS	200-watt	79	$6.08	$7.42	$13.50	841	797	$61,360	$74,884	$136,244
31	Flood	HPS	250-watt	102	$6.37	$9.58	$15.95	728	891	$55,652	$83,697	$139,349
32	Flood	HPS	400-watt	163	$6.39	$15.30	$21.69	2,013	3,937	$154,340	$369,545	$523,885
76	Shoebox	HPS	70-watt	30	$6.27	$2.82	$9.09	0	0	$0	$0	$0
77	Shoebox	HPS	100-watt	43	$6.48	$4.04	$10.52	571	294	$44,378	$27,668	$72,046
78	Shoebox	HPS	150-watt	62	$6.76	$5.82	$12.58	117	87	$9,525	$8,200	$17,725
81	Special Acorn	HPS	100-watt	43	$9.38	$4.04	$13.42	542	280	$61,013	$26,279	$87,292
82	Architectural - Victorian	HPS	150-watt	62	$9.09	$5.82	$14.91	16	12	$1,745	$1,117	$2,863
49	Architectural - Victorian	HPS	200-watt	79	$9.22	$7.42	$16.64	0	0	$0	$0	$0
83	Architectural - Victorian	HPS	250-watt	102	$9.31	$9.58	$18.89	0	0	$0	$0	$0
40	Post-Top	HPS	100-watt	43	$6.47	$4.04	$10.51	74	38	$5,745	$3,588	$9,333
48	Special - Cobrahead	MH	175-watt	71	$5.80	$6.67	$12.47	26	22	$1,810	$2,081	$3,891
60	Special - Flood	MH	400-watt	156	$6.37	$14.65	$21.02	7	13	$535	$1,231	$1,766
47	Special - Flood	HPS	750-watt	285	$8.84	$26.76	$35.60	129	440	$13,653	$41,331	$54,984
12	Acorn - Independence	HPS	100-watt	43	$8.73	$4.04	$12.77	10	5	$1,048	$485	$1,532
13	Acorn - Independence	HPS	150-watt	62	$8.74	$5.82	$14.56	33	24	$3,431	$2,284	$5,715
64	Capitol Acorn	HPS	100-watt	43	$13.05	$4.04	$17.09	9	5	$1,409	$436	$1,846
67	Capitol Acorn	HPS	150-watt	62	$13.06	$5.82	$18.88	0	0	$0	$0	$0
65	Capitol Acorn	HPS	200-watt	79	$13.06	$7.42	$20.48	0	0	$0	$0	$0
66	Capitol Acorn	HPS	250-watt	102	$13.06	$9.58	$22.64	0	0	$0	$0	$0
98	Techtra	HPS	100-watt	43	$16.40	$4.04	$20.44	3	2	$590	$145	$736
99	Techtra	HPS	150-watt	62	$16.41	$5.82	$22.23	2	1	$394	$140	$534
88	Techtra	HPS	250-watt	102	$23.05	$9.58	$32.63	0	0	$0	$0	$0
96	KIM Archetype	HPS	250-watt	102	$10.65	$9.58	$20.23	0	0	$0	$0	$0
97	KIM Archetype	HPS	400-watt	163	$10.46	$15.30	$25.76	0	0	$0	$0	$0
9	Mongoose	HPS	150-watt	62	$7.77	$5.82	$13.59	2	1	$186	$140	$326
10	Mongoose	HPS	250-watt	102	$7.86	$9.58	$17.44	0	0	$0	$0	$0
11	Mongoose	HPS	400-watt	163	$7.90	$15.30	$23.20	0	0	$0	$0	$0
Totals								21,851	24,168	$1,568,944	$2,269,403	$3,838,347
Poles												
1	SLO	Wood	30 to 35				$5.98	7,403				$531,239
3	SLO	Wood	40 to 55				$7.51	311				$28,027
11	Painted Underground	Wood	35				$6.99	150				$12,582
41	Curved laminated	Wood	30				$8.68	75				$7,812
31	Regular	Aluminum	16				$7.40	28				$2,486
32	Regular	Aluminum	25				$12.03	28				$4,042
33	Regular	Aluminum	30				$13.03	26				$4,065
28	Regular	Aluminum	35				$14.33	0				$0
65	Fluted Victorian	Aluminum	14				$14.07	19				$3,208
18	Davit	Aluminum	25				$12.43	5				$746
6	Davit	Aluminum	30				$13.25	0				$0
29	Davit	Aluminum	35				$14.65	0				$0
70	Davit with 8-foot Arm	Aluminum	40				$17.88	0				$0
27	Double Davit	Aluminum	30				$15.95	30				$5,742
66	Fluted Ornamental	Aluminum	16				$13.47	6				$970
69	Non-fluted Techtra	Aluminum	18				$25.16	21				$6,340
4	Post-Top	Concrete	25				$29.74	0				$0
63	Fluted Ornamental -Black	Fiberglass	14				$8.22	203				$20,024
57	black	Fiberglass	20				$5.20	298				$18,595
61	gray	Fiberglass	30				$6.97	1,305				$109,150
68	Regular	Fiberglass	35				$9.48	22				$2,503
16	Anchor Base	Fiberglass	35				$15.17	0				$0
35	Direct Bury with Shroud	Fiberglass	18				$7.87	102				$9,633
Totals								10,032				$767,165

Totals Luminaires and Poles $4,605,512

Schedule 123, Sales Normalization Adjustment Assessment

The Commission in Order No. 09-020 approved the Company's request to implement a decoupling mechanism as a two-year pilot. In the order, the Commission asked the Company to submit an assessment on the effectiveness of the decoupling[1] mechanism. Specifically, the Commission asked the Company to focus the assessment on the following topics and questions:

- Did the decoupling mechanism effectively remove the relationship between the utility's sales and profits?
- Did the mechanism effectively mitigate the utility's disincentives to promote energy efficiency?
- Did the mechanism improve the utility's ability to recover its fixed costs?
- Did the mechanism reduce business and other financial risk? If yes, please describe the business and financial risks that were impacted and the level of impact and effects on operations.
- What changes in the Company's culture or operating practices resulted from the implementation of the partial decoupling mechanism?
- To what extent did fixed costs covered by fixed cost-recovery factors increase with customer growth beyond what was included in the test-year load forecast in this proceeding?

Below is a brief description of Schedule 123 that implements decoupling followed by an assessment responsive to the questions posed by the Commission in OPUC Order 09-020. This assessment, based on 11 months experience supports continuation of Schedule 123 beyond January 31, 2011.

Description of Schedule 123 Sales Normalization Adjustment

PGE's Schedule 123 consist of two parts, the Sales Normalization Adjustment (SNA) applicable to PGE's residential and small non-residential customers and the Lost Revenue Recovery Adjustment (LRRA) mechanism applicable to large non-residential customers with loads less than one mega-watt average (MWa). The LRRA is only applicable to energy efficiency measures reported by the Energy Trust (ETO) attributable to the energy efficiency funding collected through Schedule 109, Energy Efficiency Funding Adjustment.

The approved mechanism decouples PGE's fixed cost recovery for residential (Schedule 7) and Small-Commercial (Schedule 32) customers and sales on a weather-adjusted basis. The mechanism compares per customer fixed cost revenues, approved for recovery in the most recent rate case, and actual weather adjusted volumetric revenues designed to recover fixed costs. This comparison is made by schedule each month for both Schedules 7 and 32. The LRRA is based on the incremental energy efficiency savings achieved by eligible large non-residential customers relative to the amount projected in the most recent general rate case.

[1] OPUC Order 09-020 page 29.

With the approval of Schedule 123, the Company implemented the necessary accounting procedures to track and record the monthly differences between fixed charge revenues and weather normalized energy revenues for Schedules 7 and 32 based on the factors set out in the rate schedule. The procedures have operated as expected and there are no identified operational issues. The Company will file proposed Schedule 123 price changes by April 1, 2010 based on the first full year as specified in Schedule 123.

Commission Questions

Did the decoupling mechanism effectively remove the relationship between the utility's sales and profits?

Yes, partially. Although residential customer counts have been less than projected in UE 197, weather adjusted sales per residential customer have been higher than projected. This divergence from forecast will result in a refund to residential customers. Customer counts for Schedule 32 have also been below forecast, but contrary to Schedule 7, sales per customer have been less than forecast. This will result in a surcharge to Schedule 32 customers[2]. Absent the partial decoupling mechanism PGE would not be refunding residential customers, nor recovering lost margins from small commercial customers.

Did the mechanism effectively mitigate the utility's disincentives to promote energy efficiency?

The Company's short-term experience indicates that the current mechanism helps to mitigate the disincentives to promote energy efficiency to customer classes covered under the decoupling mechanism. During 2009, PGE continued to support ETO energy efficiency programs and supported increased funding for energy efficiency (called SB 838 funding) for 2010. In 2009, the Company also issued a new Integrated Resource Plan (IRP) with aggressive energy efficiency (EE) goals. This IRP specifies a long-term goal of meeting approximately 23%[3] of its future resource needs through energy efficiency. Additionally, PGE has helped to expand the number of net metering installations over the past two years. The Company also filed demand response pilots for both residential and large non-residential customers.

In its day-to-day operations, in collaboration with the Energy Trust, PGE continues to promote energy efficiency actions across all of its customer segments. For example, in 2009, PGE's monthly residential update letter included energy efficiency tips and/or actions reaching the residential customer base at least once a month. In April 2009, after the monthly news update featured the refrigerator-recycling program run by the Energy Trust, the number of refrigerators recycled increased by 115%[4]. On the non-residential side, the Company continued its Save More Matter More promotion and implemented targeted direct mail campaigns on energy efficiency.

---

[2] Final decoupling results for 2009 will be available by April 1, 2010.
[3] PGE 2009 Integrated Resource Plan, page 317
[4] Quarter 2, 2009 Report to OPUC by ETO August 14, 2009
http://energytrust.org/library/reports/2009_Q2_PUC0.pdf

What changes in the Company's culture or operating practices resulted from the implementation of the partial decoupling mechanism?

Because the Company has been supporting energy efficiency for years, cultural or attitude changes are difficult to identify. Nevertheless, the existence of a decoupling mechanism allows for broader awareness within the Company regarding structural or behavioral changes in customer's energy consumption. Examples include energy efficiency measures and renewable energy generation. Specific examples are given above.

Did the mechanism reduce business and other financial risk? If yes, please describe the business and financial risks that were impacted and the level of impact and effects on operations.

The impact of the Schedule 123 decoupling mechanism on the Company's business and financial risks is difficult to assess, in particular given the brief experience. Nevertheless, the Company supports continuing decoupling as a reasonable implementation of good public policy. This question is further addressed in PGE Exhibit 1100.

Did the mechanism improve the utility's ability to recover its fixed costs? To what extent did fixed costs covered by fixed cost-recovery factors increase with customer growth beyond what was included in the test-year load forecast in this proceeding?

The decoupling mechanism improves PGE's ability to recover its per customer fixed costs at forecasted levels approved by the Commission in its most recent rate case (UE-197); however, Schedule 123 is not a full decoupling mechanism in that the mechanism reflects only weather-normalized sales and does not fully true-up fixed cost recovery because large nonresidential customers are not decoupled. Because PGE's customer count was below that forecast in UE 197, PGE is unable evaluate whether fixed costs increased due to customer growth beyond what was included in the test-year load forecast.

Assessment

The Schedule 123 decoupling mechanism has operated in a manner consistent with the intent of the mechanism and PGE has not identified any problems in the mechanism. The approved decoupling mechanism appropriately aligns the incentives for both customers and the Company. Its continuation is warranted in order to properly align public policy and utility incentives with respect to energy efficiency.