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

September 30, 2009

Via Electronic Filing and U.S. Mail

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

RE: UM 1443 - INVESTIGATION INTO IF THE AVOIDED COST RATE IS CONSISTENT WITH ORDER NO. 05-584

Attention Filing Center:

Enclosed for filing in UM 1443 are an original and five copies of:

Direct Testimony of Portland General Electric Company

- **PGE Exhibit 100-104 Kuns**

This document is being filed by electronic mail with the Filing Center. An extra copy of the cover letter is enclosed. Please date stamp the extra copy and return to me in the envelope provided.

This document is being served upon the UM 1443 service list.

Thank you in advance for your assistance.

Sincerely,

Randy J. Dahlgren
Director, Regulatory Policy and Affairs

Enclosures
cc: Service List UM 1443

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused **PORTLAND GENERAL ELECTRIC DIRECT TESTIMONY AND EXHIBITS** in Docket UM 1443, to be served by electronic mail to those parties whose email addresses appear on the attached service list, and by First Class US Mail, postage prepaid and properly addressed, to those parties on the attached service list who have not waived paper service.

Dated this 30th day of September, 2009.

Mary Widman

Mary Widman
Specialist II, Rates and Regulatory Affairs
On behalf of Portland General Electric Company

SERVICE LIST

OPUC DOCKET NOS. UM 1443

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BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UM 1443

Investigation Into if the Avoided Cost Rate is Consistent with Order No. 05-584

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony

September 30, 2009

Table of Contents

I. Introduction

Q. Please state your names and positions.

A. My name is Doug Kuns. I am employed by Portland General Electric Company as Manager of Pricing and Tariffs. My qualifications are described in Section VI.

Q. What is the purpose of your testimony?

A. The Commission initiated Docket UM 1443 to investigate whether PGE properly calculated avoided cost prices in its current Schedule 201, following the methodologies outlined in Commission Order No. 05-584.

This testimony describes the methodology, inputs and calculations used to establish the avoided cost prices in PGE's Schedule 201 as filed on July 10, 2009 and subsequently approved subject to this investigation on September 8, 2009. The testimony explains that: (1) the methodologies from Commission Order No. 05-584 were followed, (2) the proper inputs were used, and (3) the calculations involved are accurate.

Further, this testimony also describes a proposed input change related to the appropriate long-term natural gas price forecast used to compute avoided costs from 2013 through 2028. I believe a revision is necessary to make the gas prices consistent with those used in PGE's recently released draft 2009 Integrated Resource Plan. This change adjusts the resulting avoided cost prices upward beyond 2013. No changes to the avoided cost methodology are made.

Q. How is your testimony organized?

A. My testimony is organized as follows:

First, Schedule 201 is described including the pricing options.

Second, I explain the overall avoided cost calculations and the basis for the methodology.

Third, I present the basis for the long-term natural gas price forecast used in computing avoided costs in the resource deficiency period. We also propose that the gas prices be updated to be consistent with PGE's recently submitted draft 2009 Integrated Resource Plan (IRP).

II. Schedule 201

Q. What is Schedule 201?

A. PGE's Schedule 201, Avoided Cost Power Purchase Information, offers a standard contract for Qualifying Facilities (QFs) with a nameplate capacity of 10 MW or less, consistent with Commission Order No. 05-584, pages 17 and 40.

Q. What pricing options does PGE offer in Schedule 201?

A. Four pricing options are available for Standard Contracts. The pricing options include one fixed rate option and three market based options. The market based options include: deadband index gas price option, index gas price option, and Mid-C index price option.

Q. On what pricing options does this testimony focus?

A. This testimony focuses primarily on the fixed price option. However, some of the data used to calculate the fixed price option are also used in the deadband index gas price option and the index gas price option.

Q. What avoided cost information is presented in Schedule 201?

A. Schedule 201 is shown in PGE Exhibit 101 and includes seven numerical tables that present avoided cost-based pricing information necessary for a potential QF to elect one of the avoided cost pricing options described above. Specifically, Tables 1 and 2 set out the fixed avoided cost prices by year and by month for on-peak and off-peak QF power deliveries to the Company under a Standard Contract. The remaining tables provide monthly price information details allowing other pricing options to be selected.

III. Avoided Cost Calculation

Q. What are avoided costs as they relate to the standard power purchase agreement?

A. "Avoided costs mean the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source" [18 CFR Part 292.101(b)(6)]. Avoided costs reflect projections of year-by-year PGE avoided system costs. The avoided costs are reflected in Schedule 201.

Q. How is pricing determined for the fixed price option?

A. Order No. 05-584 page 27 states that during resource sufficiency periods, a utility is required to use forward market curves as the basis for the avoided resource. When a utility is resource deficient, avoided energy and capacity values are based on the costs of a proxy generation plant, using the variable and fixed costs of a natural gas-fired Combined Cycle Combustion Turbine (CCCT).

Q. What are the resource sufficiency and deficiency periods for the current Schedule 201?

A. Concurrent with PGE's draft IRP analysis, avoided costs are based on adding a resource in 2013. During the resource sufficiency time frame, from 2009 through 2012, the avoided resource is based on a forward curve. From 2013 through 2028, total avoided costs are based on costs of a CCCT. Avoided capacity costs are based on the fixed costs of a simple-cycle combustion turbine (SCCT).

PGE's draft IRP supports the resource additions in 2013. Until at least that time PGE will use market purchases to balance both capacity and energy needs. Avoided costs properly reflect short to mid-term market purchases which will be used to balance load and resources through 2012.

Q. Does the regional outlook support this deficiency date?

A. Yes. Market purchases are forecast to be available in the region through at least 2013. The Northwest Power and Conservation Council's Power Supply Outlook Update from February 2009 indicates, "The likelihood of a significant power shortage over the next five years due to an inadequate supply continues to be minimal. Based on the 2008 Assessment the region's annual supply of energy from existing sources is projected to be about 1,900 average megawatts over the minimum adequacy threshold by 2013."

Q. What electric forward price curves were used in the filing for 2009 through 2012?

A. The electric forward price curve was derived from monthly on- and off-peak market quotes as of May 14, 2009. The 2009 through 2011 prices are based on information from broker quotes that PGE's traders observe. Since the market is not liquid in 2012, the 2010 calendar price is used to impute or shape the 2012 price. Last, we use similar forward price curves in PGE's Net Variable Power Cost Annual Update Tariff (AUT) filing. The curve in the 2010 AUT uses Mid-C on- and off-peak prices for only the test year (e.g. 2010).

Q. What information was provided in the work papers in Advice Filing 09-16?

A. The supporting avoided cost work papers include a brief description of the study (pages 1-3), various costs and prices (Tables 1-12), natural gas price forecast (Tables 13 and 14), and financial parameters and cost-of-capital data (Table 15). The avoided cost work papers in Advice Filing 09-16 are provided in PGE Exhibit 102. The model, which provides these tables as well as other supporting data, was provided electronically (on CD) with the Advice Filing.

Q. Please describe the avoided cost methodology and calculations in Exhibit 102, Workpaper Tables 1-5.

A. Workpaper Tables 1 through 5 summarizes PGE avoided cost data consistent with Commission Order No. 05-584. Workpaper Tables 1 and 2 are estimates of monthly on- and off-peak avoided costs for energy and capacity. Table 3 provides flat monthly avoided costs, and Tables 4 and 5 show the on- and off-peak resource sufficiency rates.

Q. Can you explain Exhibit 102 Workpaper Tables 1 and 2 in more detail?

A. Workpaper Tables 1 and 2 are estimates of monthly on- and off-peak avoided costs for energy and capacity for twenty years beginning August 2009 and ending December 2028. Using 2028 as an end date gives any QFs signing a contract in the next two years at least 15 years of fixed pricing consistent with Commission Order No. 05-584, pages 27-28. The prices (expressed in $/MWh or mills/kWh) for the years 2009 through 2012 are based on forward curves.

Capacity value is included in the avoided costs. On-peak prices for 2013 to 2028 include capacity and energy costs, while off-peak prices reflect energy costs only. The on-peak price includes the following costs of a CCCT: fuel, variable operations and maintenance (O&M), capacity, and other fixed costs. The off-peak price includes: fuel, variable O&M, and other fixed costs.

The "other fixed costs" represent the energy portion of the fixed costs of a CCCT. They are calculated by taking the fixed costs of a CCCT minus the real levelized capital carrying cost and fixed O&M of an SCCT. The result (other fixed costs) represents the energy portion of the fixed costs of a CCCT. On-peak periods are from 6 a.m. through 10 p.m.

Mondays through Saturdays. The off-peak hours are from 10 p.m. until 6 a.m. Mondays through Saturdays and all twenty-four hours on Sundays and NERC holidays.

Q. Please describe the avoided cost methodology and calculations in Exhibit 201, Workpaper Tables 6-12.

A. Workpaper Tables 6 through 12 show the capacity, fixed, variable, and gas forecast components for avoided costs.

- Tables 6 and 7 show the on- and off-peak SCCT-related capacity costs. The capacity values are applicable to on-peak hours only, thus Table 7 is left blank.
- Table 8 contains the energy portion of a CCCT, calculated using fixed costs of a CCCT minus the real levelized capital carrying cost and fixed O&M of an SCCT.
- Table 9 shows the variable O&M cost associated with the CCCT. This cost is determined by dividing the variable O&M by one minus the line loss value.
- Table 10 shows the projected fuel costs. This cost is determined by dividing the on-peak market price by one minus the line loss value
- Table 11 contains the forecasted gas prices in $/MMbtu (which is an average of the natural gas prices).
- Table 12 shows the variable O&M, fixed costs and gas transportation forecast.

Q. Can Tables 6, 8, 9, and 10 be summed to equal costs in Exhibit 102, Workpaper Tables 1 and 2?

A. Yes. Tables 6, 8, 9, and 10 can be summed to equal the total on-peak avoided costs in Table 1. Also, Tables 7, 8, 9, and 10 can be summed to equal the total off-peak avoided costs in Table 2.

Q. Please describe the information shown in PGE Exhibit 102, Workpapers Table 15?

A. Table 15 summarizes the key financial and cost of capital and related economic assumptions used to compute the avoided costs. These inputs include costs for the SCCT and CCCT avoided generating resources and are consistent with the IRP.

Q. On Workpapers Table 15, can you provide supporting data for the installed capital cost for the SCCT and the CCCT calculations?

A. Yes. The capital costs for both the CCCT and SCCT are based on information equivalent to that used in Company's draft IRP. The draft PGE 2009 IRP includes a thorough explanation of the costs of a variety of generating technologies including SCCT and CCCT units. More specifically, the draft IRP, Chapter 7, pages 143 through 146 provide the cost basis for the capital costs and a reference comparison of resource costs from various non-PGE sources. The resource costs used in this avoided cost are consistent with the IRP for a CCCT and SCCT.

IV. Gas Price Forecast and Proposed Price Revision

Q. How is PGE's gas price forecast developed?

A. The basis for the gas prices used in this study is the average of the forecasted AECO and Sumas gas prices, adjusted for transportation costs. Monthly gas forecasts through 2025 were developed using an annual price forecast from a third party forecasting service, PIRA Energy Group (PIRA), and include monthly shaping factors based on recent NYMEX prices. For a PGE specific gas index both the AECO and Sumas trading hubs were used. Prices for 2026 and beyond were extrapolated from the PIRA 2025 forecasts escalated at an assumed inflation rate of 1.9%.

Q. Where does the gas price forecast appear in Schedule 201?

A. The gas price forecast appears in Table 5, expressed in $/MMBTU and does not include gas transportation.

Q. How are gas transportation costs addressed?

A. In order to simplify market-based pricing, the estimate of gas transportation costs is fixed. The heat rate of a CCCT is then applied to the estimated transportation costs for both the AECO and Sumas trading hubs. This gas transportation estimate is added to the fixed and variable O&M costs to calculate Table 6 in Schedule 201, found in PGE Exhibit 101.

Q. Please explain the proposed revision to the long-term gas price forecast used to calculate avoided costs and the purpose of the update?

A. The Schedule 201 avoided costs from PGE Exhibit 101 described above reflect gas prices as filed in July and are used during the resource deficiency period which begins in 2013. Our draft IRP was submitted on September 4, 2009; however the long-term gas price forecast used in the July avoided cost filing was not consistent with the draft IRP gas price forecast.

The revised long-term gas price inputs presented in PGE Exhibit 103 are consistent with the draft IRP inputs. The effect of the gas price revision is an increase in avoided cost prices throughout the deficiency period (2013 through 2028). A copy of PGE's draft 2009 IRP is at www.PortlandGeneral.com/IRP. Chapter 5 – *Fuels* provides an additional discussion on the February 2009 gas price forecast.

PGE Exhibit 104 presents the revised Schedule 201 avoided cost prices if the updated gas forecast is adopted. Each table in PGE Exhibit 104 corresponds to the equivalent table in Schedule 201 (PGE Exhibit 101).

Q. Do you provide a revised long-term gas price forecast without transportation costs?

A. Yes. PGE Exhibit 103 provides a revision to the gas price forecast without transportation costs that was used in our July 10, 2009 Schedule 201 filing. This forecast is located in Table 5 in Schedule 201.

Q. How will the updated gas prices be incorporated in the Schedule 201 avoided cost pricing?

A. At the conclusion of this investigation we expect the Commission will order PGE to file revised Schedule 201 avoided costs that comply with all findings by the Commission with respect to the inputs into the avoided costs. The gas price forecast is one of the inputs that the Company should update in a compliance filing. Given that all inputs into avoided costs are a subject of this investigation, we are not separately filing tariff revisions outside of this investigation in order to minimize potential confusion.

We believe that incorporating the gas price revisions at the conclusion of the UM 1443 process is appropriate and will not in any way disadvantage potential QFs given that the revisions related to the gas price forecast do not affect avoided costs until 2013 and that the

Commission will require any contracts signed in the near future to be revised to reflect the updated avoided cost prices.

V. Conclusions

Q. Please summarize your testimony.

A. The testimony presented provides an overview of the avoided cost methodology and inputs into the calculation of avoided costs. The methodology is consistent with historical practice based on the Commission's directives stated in Order No. 05-584.

The testimony also presents a proposed update to PGE's avoided costs based on a long-term natural gas price consistent with PGE's recently filed draft IRP.

Q. Does this conclude your testimony?

A. Yes.

VI. Qualifications

Q. Mr. Kuns, please state your educational background and qualifications.

A. I graduated from Linfield College in 1973 with a BA in economics. I received a Masters Degree in Business Administration from Claremont Graduate School in 1975.

In 1979, I joined PGE in the Rates Department and have held various positions in the regulatory, marketing and planning areas at PGE. My current position is Manager, Pricing and Tariffs.

List of Exhibits

PGE Exhibit	Description
101	PGE Schedule 201 without Standard Agreements
102	Workpapers filed with Advice Filing 09-16
103	Proposed Revised Gas Price Forecast
104	Proposed Revised PGE Schedule 201, Tables 1 through 7

SCHEDULE 201
QUALIFYING FACILITY 10 MW or LESS
AVOIDED COST POWER PURCHASE INFORMATION

PURPOSE

To provide information about Avoided Costs, Standard Contracts and negotiated Power Purchase Agreements, power purchase prices and price options for power delivered by a Qualifying Facility (QF) to the Company with nameplate capacity of 10,000 kW (10MW) or less. **(T)**

AVAILABLE

To owners of QFs making sales of electricity to the Company in the State of Oregon (Seller).

APPLICABLE

For power purchased from small power production or cogeneration facilities that are QFs as defined in 18 Code of Federal Regulations (CFR) Section 292, that meet the eligibility requirements described herein and where the energy is delivered to the Company's system and made available for Company purchase pursuant to a Standard Contract Power Purchase Agreement.

ESTABLISHING CREDITWORTHINESS

The Seller must establish creditworthiness prior to service under this schedule. For a Standard Contract Power Purchase Agreement (Standard Contract), a Seller may establish creditworthiness with a written acknowledgment that it is current on all existing debt obligations and that it was not a debtor in a bankruptcy proceeding within the preceding 24 months. If the Seller is not able to establish creditworthiness, the Seller must provide security as deemed sufficient by the Company as set out in the Standard Contract.

POWER PURCHASE INFORMATION

A Seller may call the Power Production Coordinator at (503) 464-8000 to obtain more information about being a Seller or how to apply for service under this schedule.

SCHEDULE 201 (Continued)

POWER PURCHASE AGREEMENT

In accordance with terms set out in this schedule and the Commission's Rules as applicable, the Company will purchase any Energy in excess of station service (power necessary to produce generation) and amounts attributable to conversion losses, which are made available from the Seller.

A Seller must execute a Power Purchase Agreement with the Company prior to delivery of power to the Company. The agreement will have a term of up to 20 years as selected by the QF.

A QF with a nameplate capacity rating of 10 MW or less as defined herein may elect the option of a Standard Contract.

Any Seller may elect to negotiate a Power Purchase Agreement with the Company. Such negotiation will comply with the requirements of the Federal Energy Regulatory Commission (FERC), and the Commission including the guidelines in Order No. 07-360, and Schedule 202. Negotiations for power purchase pricing will be based on the filed Avoided Costs in effect at that time.

STANDARD CONTRACTS (Nameplate capacity of 10 MW or less)

A Seller choosing a Standard Contract will complete all informational and price option selection requirements in the applicable Standard Contract (Appendix 1 to this schedule) and submit the executed Agreement to the Company prior to service under this schedule. The Standard Contract is available at www.portlandgeneral.com. The available Standard Contracts are: Standard Contract Power Purchase Agreement, Standard Contract Off System Power Purchase Agreement, Standard Contract for Intermittent Resources and Standard Contract for Off System Intermittent Resources. The Standard Contracts applicable to Intermittent Resources are available only to QFs utilizing wind, solar or run of river hydro as the primary motive force.

GUIDELINES FOR 10 MW OR LESS FACILITIES **(T)**

In order to execute the Standard Contract the Seller must complete all of the general project information requested in the applicable Standard Contract.

When all information required in the Standard Contract has been received in writing from the Seller, the Company will respond within 15 business days with a draft Standard Contract.

The Seller may request in writing that the Company prepare a final draft Standard Contract. The Company will respond to this request within 15 business days. In connection with such request, the QF must provide the Company with any additional or clarified project information that the Company reasonably determines to be necessary for the preparation of a final draft Standard Contract.

When both parties are in full agreement as to all terms and conditions of the draft Standard Contract, the Company will prepare and forward to the Seller a final executable version of the agreement within 15 business days. Following the Company's execution, a completely executed copy will be returned to the Seller. Prices and other terms and conditions in the power purchase agreement will not be final and binding until the Standard Contract has been executed by both parties.

SCHEDULE 201 (Continued)

OFF SYSTEM POWER PURCHASE AGREEMENT

A Seller with a facility that interconnects with an electric system other than the Company's electric system may enter into a power purchase agreement with the Company after following the applicable standard or negotiated contract guidelines and making the arrangements necessary for transmission of power to the Company's system.

BASIS FOR POWER PURCHASE PRICE

AVOIDED COST SUMMARY

The power purchase rates are based on the Company's Avoided Costs. Avoided Costs are defined in 18 CFR 292.101(6) as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."

The Avoided Costs as listed in Tables 1 and 2 below include monthly On- and Off-Peak prices.

ON-PEAK PERIOD

The On-Peak period is 6:00 a.m. until 10:00 p.m., Monday through Saturday.

OFF-PEAK PERIOD

The Off-Peak period is 10:00 p.m. until 6:00 a.m., Monday through Saturday, and all day on Sunday.

Avoided Costs are based on forward market price estimates through December 2012, the (C)
period of time during which the Company's Avoided Costs are associated with incremental purchases of Energy and capacity from the market. For the period 2013 through 2028, the (C)
Avoided Costs reflect the fully allocated costs of a natural gas fueled combined cycle combustion turbine (CCCT) including fuel and capital costs. The CCCT Avoided Costs are based on the variable cost of Energy plus capitalized Energy costs at a 93% capacity factor based on a natural gas price forecast, with prices modified for shrinkage and transportation costs.

PRICING OPTIONS FOR STANDARD CONTRACTS

Pricing options represent the purchase price per MWh the Company will pay for electricity delivered to a Point of Delivery (POD) within the Company's service territory pursuant to a Standard Contract up to the nameplate rating of the QF in any hour. Any Energy delivered in excess of the nameplate rating will be purchased at the applicable Off-Peak Prices for the selected pricing option.

The Standard Contract pricing will be based on the Avoided Cost in effect at the time the agreement is executed.

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD CONTRACTS (Continued)

Four pricing options are available for Standard Contracts. The pricing options include one Fixed Rate Option and three Market Based Options.

1) Fixed Price Option

The Fixed Price Option is based on Avoided Costs including forecasted natural gas prices.

This option is available for a maximum term of 15 years. Sellers with contracts exceeding 15 years will make a one time election at execution to select a Market-Based Option for all years up to five in excess of the initial 15. Under the Fixed Price Option, prices will be as established at the time the Standard Contract is executed and will be equal to the Avoided Costs in Tables 1 and 2 effective at execution for a term of up to 15 years.

TABLE 1
Avoided Costs
Fixed Price Option
On-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
2009	N/A	N/A	N/A	N/A	N/A	N/A	N/A	32.71	31.59	32.46	41.21	50.34	**(C)**
2010	51.25	47.75	42.75	41.00	36.00	33.25	53.75	58.25	57.75	53.75	56.00	59.25	
2011	60.30	56.80	53.55	47.55	40.80	39.55	64.05	66.80	63.55	58.80	62.05	65.05	
2012	62.07	57.81	51.71	49.58	43.48	40.13	65.12	70.61	70.00	65.12	67.86	71.83	
2013	97.44	97.41	95.83	90.96	90.67	91.16	91.72	92.21	92.38	92.90	94.45	96.26	
2014	96.31	96.28	94.76	90.04	89.79	90.26	90.83	91.27	91.46	91.99	93.47	95.24	
2015	94.54	94.51	93.07	88.60	88.36	88.81	89.35	89.76	89.94	90.45	91.85	93.52	
2016	94.77	94.74	93.32	88.90	88.66	89.11	89.64	90.05	90.23	90.73	92.12	93.77	
2017	97.00	96.97	95.52	90.99	90.75	91.21	91.75	92.17	92.35	92.86	94.28	95.97	
2018	100.22	100.19	98.67	93.92	93.66	94.14	94.71	95.15	95.34	95.88	97.37	99.15	
2019	104.73	104.70	103.07	97.98	97.71	98.22	98.83	99.30	99.51	100.08	101.68	103.58	
2020	105.39	105.35	103.73	98.65	98.38	98.89	99.50	99.97	100.17	100.75	102.34	104.23	
2021	107.84	107.81	106.14	100.94	100.67	101.19	101.81	102.29	102.50	103.09	104.72	106.66	
2022	110.17	110.13	108.43	103.10	102.82	103.35	103.99	104.49	104.70	105.30	106.97	108.96	
2023	113.96	113.92	112.13	106.56	106.26	106.82	107.49	108.01	108.23	108.86	110.61	112.69	
2024	117.35	117.31	115.45	109.62	109.31	109.89	110.59	111.13	111.37	112.03	113.85	116.03	
2025	119.74	119.70	117.80	111.86	111.55	112.14	112.85	113.41	113.65	114.32	116.18	118.40	
2026	122.01	121.97	120.04	113.99	113.66	114.27	115.00	115.56	115.80	116.49	118.38	120.64	
2027	124.33	124.29	122.32	116.15	115.82	116.44	117.18	117.75	118.00	118.70	120.63	122.93	
2028	126.65	126.61	124.60	118.32	117.98	118.61	119.37	119.95	120.20	120.91	122.88	125.23	**(C)**

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD CONTRACTS (Continued)
FIXED PRICE OPTION (Continued)

TABLE 2
Avoided Costs
Fixed Price Option
Off-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	(C)
2009	N/A	N/A	N/A	N/A	N/A	N/A	N/A	26.59	27.21	27.71	35.21	43.71	
2010	44.75	42.75	37.75	34.75	26.25	23.75	40.25	44.00	41.75	42.75	48.75	55.25	
2011	55.30	51.80	48.05	36.80	29.80	27.30	45.30	50.55	50.30	49.80	53.80	57.05	
2012	53.00	50.62	44.66	41.08	30.95	27.97	47.64	52.11	49.42	50.62	57.77	65.52	
2013	64.67	64.64	63.06	58.19	57.89	58.39	58.94	59.44	59.60	60.13	61.68	63.49	
2014	62.91	62.88	61.37	56.64	56.39	56.86	57.43	57.87	58.06	58.60	60.08	61.84	
2015	60.51	60.48	59.04	54.57	54.33	54.78	55.32	55.73	55.91	56.42	57.82	59.49	
2016	60.20	60.17	58.76	54.33	54.10	54.54	55.07	55.48	55.66	56.16	57.55	59.20	
2017	61.55	61.52	60.07	55.55	55.30	55.76	56.30	56.72	56.90	57.42	58.83	60.52	
2018	64.22	64.19	62.66	57.91	57.66	58.13	58.70	59.15	59.34	59.88	61.37	63.14	
2019	68.04	68.01	66.38	61.29	61.02	61.53	62.14	62.61	62.82	63.39	64.99	66.89	
2020	68.12	68.08	66.46	61.38	61.11	61.62	62.23	62.70	62.91	63.48	65.07	66.97	
2021	69.74	69.71	68.04	62.84	62.57	63.09	63.71	64.20	64.40	64.99	66.62	68.56	
2022	71.34	71.31	69.60	64.28	63.99	64.53	65.17	65.66	65.88	66.48	68.15	70.14	
2023	74.27	74.23	72.45	66.87	66.57	67.13	67.80	68.32	68.54	69.18	70.92	73.01	
2024	77.17	77.13	75.26	69.44	69.12	69.71	70.41	70.95	71.18	71.84	73.67	75.84	
2025	78.66	78.62	76.72	70.79	70.47	71.06	71.78	72.33	72.57	73.24	75.10	77.32	
2026	80.16	80.12	78.18	72.13	71.81	72.41	73.14	73.70	73.94	74.63	76.53	78.78	
2027	81.68	81.64	79.66	73.50	73.17	73.78	74.52	75.10	75.35	76.04	77.98	80.28	
2028	83.19	83.15	81.14	74.85	74.52	75.15	75.90	76.49	76.74	77.45	79.42	81.77	(C)

Under the Fixed Price Option, the Company will pay Seller the Off-Peak Avoided Cost pursuant to Table 2 for: (a) all Net Output delivered prior to the Commercial Operation Date; (b) all Net Output deliveries greater than Maximum Net Output in any Contract Year; (c) any generation subject to and as adjusted by the provisions of Section 4.3 of the Standard Contract; (d) Net Output delivered in the
Off-Peak Period; and (e) deliveries above the nameplate capacity in any hour. The Company will (C)
pay the Seller the On-Peak Avoided Cost pursuant to Table 1 for all other output. (See Appendix 1, (C)
the Standard Contract for defined terms.)

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD CONTRACTS (Continued)

MARKET BASED PRICE OPTIONS:

Market Based Price Options include Option 2, Deadband Index Gas Price; Option 3, Index Gas Price; and Option 4, Dow Jones Mid-Columbia Daily On- and Off-Peak Electricity Firm Price Index (DJ-Mid-C Firm Index). The price components for pricing Options 2 and 3 are defined as follows:

On Peak Price:	P_{Peak}
Off Peak Price:	P_{Off}
Variable Operating and Maintenance, Fixed Costs, and Gas Transportation (Table 6):	VFG
Capacity Value (Table 7):	C
Heat Rate:	HR = 6,732 BTU/kWh **(C)**
Losses:	1.9%
Forecasted Gas Price (Table 5):	GP_F
First of Month* Northwest Pipeline Corp. Canadian Border Index as Reported in <u>Platts Inside FERC's Gas Market Report</u>	GP_{Sumas}
First of Month* one-month spot price averages for AECO/NIT transactions as Reported in <u>Canadian Gas Price Reporter Natural Gas Market Report</u> (in US dollars):	GP_{AECO}
Monthly Indexed Gas Price:	$GP_{MI} = (GP_{Sumas} + GP_{AECO})/2$
Deadband Gas Index:	GP_{DB}

Where:
If $GP_{MI} > GP_F$
GP_{DB} = Minimum of (GP_{MI} or $1.1*GP_F$)
Otherwise
GP_{DB} = Maximum of (GP_{MI} or $.9*GP_F$)

* "First of Month" means the first such monthly issuance.

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD CONTRACTS (Continued)
MARKET BASED PRICE OPTIONS (Continued)

Tables 3 and 4 below list applicable rates for Options 2 (Deadband Index Gas Price Option) and 3 (Index Gas Price Option) for the period through 2012. The monthly On- and Off-Peak prices will be applied for all Market Based Price Options. **(C)**

TABLE 3
Avoided Costs **(T)**
On-Peak Resource Sufficiency Rate ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
2009	N/A	N/A	N/A	N/A	N/A	N/A	N/A	32.71	31.59	32.46	41.21	50.34	**(C)**
2010	51.25	47.75	42.75	41.00	36.00	33.25	53.75	58.25	57.75	53.75	56.00	59.25	
2011	60.30	56.80	53.55	47.55	40.80	39.55	64.05	66.80	63.55	58.80	62.05	65.05	
2012	62.07	57.81	51.71	49.58	43.48	40.13	65.12	70.61	70.00	65.12	67.86	71.83	**(C)**

TABLE 4
Avoided Costs **(T)**
Off-Peak Resource Sufficiency Rate ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
2009	N/A	N/A	N/A	N/A	N/A	N/A	N/A	26.59	27.21	27.71	35.21	43.71	**(C)**
2010	44.75	42.75	37.75	34.75	26.25	23.75	40.25	44.00	41.75	42.75	48.75	55.25	
2011	55.30	51.80	48.05	36.80	29.80	27.30	45.30	50.55	50.30	49.80	53.80	57.05	
2012	53.00	50.62	44.66	41.08	30.95	27.97	47.64	52.11	49.42	50.62	57.77	65.52	**(C)**

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD CONTRACTS (Continued) **(M)**

MARKET BASED PRICE OPTIONS (Continued)

2) Deadband Index Gas Price Option

The Deadband Index Gas Price Option bases the fuel price component of the Energy rate on comparisons between the Forecast Gas Price (Table 5) and the simple average of the First of Month gas indices for Sumas and AECO trading hubs. The Northwest Pipeline Gas Index (Sumas) will be as reported in Platts Inside FERC's Gas Market Report. The AECO/NIT (AECO) Gas Index will be as reported in Canadian Gas Price Reporter Natural Gas Market Report (in US dollars). The fuel price component used will be bound between 90% and 110% of the natural gas price forecast but based on the then current gas price.

The price paid per MWh will be:

$$P_{Peak} = GP_{DB}*HR/1,000/(1\text{-}Losses) + VFG + C$$
$$P_{Off} = GP_{DB}*HR/1,000/(1\text{-}Losses) + VFG$$

Under the Deadband method, the Company will pay Seller the Off-Peak prices for: (a) all Net Output delivered prior to the Commercial Operation Date; (b) all Net Output deliveries greater than Maximum Net Output in any Contract Year; (c) any generation subject to and as adjusted by the provisions of Section 4.3 of the Standard Contract; (d) Net Output delivered in the Off-Peak Period; and (e) deliveries above the nameplate capacity in any hour. All other purchases will be at On-Peak prices. (See Appendix 1, the Standard Contract for defined terms.)

(M)

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD CONTRACTS (Continued)
MARKET BASED PRICE OPTIONS (Continued)

3) Index Gas Price Option

The Index Gas Price Option is the simple average of the First of Month gas indices for Sumas and AECO trading hubs used in establishing the Avoided Costs. The Sumas Gas Index will be as reported in Platts Inside FERC's Gas Market Report. The AECO Gas Index will be as reported in the Canadian Gas Price Reporter Natural Gas Market Report (in US dollars).

The price paid per MWh will be:

$$P_{Peak} = GP_{MI}*HR/1{,}000/(1\text{-}Losses) \ +VFG \ +C$$
$$P_{Off} = GP_{MI}*HR/1{,}000/(1\text{-}Losses) \ +VFG$$

Under the Index Gas Price, the Company will pay Seller the Off-Peak Prices for: (a) for all Net Output delivered prior to the Commercial Operation Date; (b) all Net Output deliveries greater than Maximum Net Output in any Contract Year; (c) any generation subject to and as adjusted by the provisions of Section 4.3 of the Standard Contract; (d) for Net Output delivered in the Off-Peak Period; and (e) deliveries above the nameplate capacity in any hour. All other purchases will be at On-Peak prices. (See Appendix 1, the Standard Contract for defined terms.)

4) Mid C Index Price Option

Under this option, prices paid per MWh will be based on the DJ-Mid-C Firm Index plus 0.221 ¢ per kWh for wholesale wheeling. **(I)**

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD CONTRACTS (Continued)
MARKET BASED PRICE OPTIONS (Continued)

Table 5 contains the gas pricing components for Option 1 (Fixed Price Option) and Option 2 (Deadband Index Gas Price Option). **(T)**

TABLE 5
Forecasted Gas Price - GP_F ($/MMBTU) - Without Transportation **(T)**

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
2013	7.41	7.41	7.18	6.48	6.44	6.51	6.59	6.66	6.69	6.76	6.98	7.24	**(C)**
2014	7.13	7.12	6.90	6.23	6.19	6.26	6.34	6.40	6.43	6.51	6.72	6.97	
2015	6.75	6.74	6.54	5.89	5.86	5.92	6.00	6.06	6.09	6.16	6.36	6.60	
2016	6.67	6.67	6.46	5.83	5.79	5.86	5.93	5.99	6.02	6.09	6.29	6.53	
2017	6.82	6.82	6.61	5.96	5.93	5.99	6.07	6.13	6.16	6.23	6.43	6.67	
2018	7.17	7.16	6.94	6.26	6.23	6.29	6.38	6.44	6.47	6.54	6.76	7.01	
2019	7.68	7.67	7.44	6.71	6.67	6.74	6.83	6.90	6.93	7.01	7.24	7.51	
2020	7.65	7.65	7.41	6.69	6.65	6.72	6.81	6.88	6.91	6.99	7.22	7.49	
2021	7.84	7.84	7.60	6.85	6.81	6.89	6.98	7.05	7.08	7.16	7.39	7.67	
2022	8.03	8.02	7.78	7.02	6.98	7.05	7.14	7.22	7.25	7.33	7.57	7.86	
2023	8.41	8.40	8.15	7.35	7.30	7.38	7.48	7.56	7.59	7.68	7.93	8.23	
2024	8.79	8.78	8.51	7.68	7.63	7.72	7.82	7.89	7.93	8.02	8.28	8.60	
2025	8.95	8.95	8.67	7.82	7.78	7.86	7.97	8.04	8.08	8.18	8.44	8.76	
2026	9.12	9.12	8.84	7.97	7.93	8.01	8.12	8.20	8.23	8.33	8.60	8.93	
2027	9.30	9.29	9.01	8.12	8.08	8.16	8.27	8.35	8.39	8.49	8.77	9.10	
2028	9.47	9.47	9.18	8.28	8.23	8.32	8.43	8.51	8.55	8.65	8.93	9.27	**(C)**

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD CONTRACTS (Continued)
MARKET BASED PRICE OPTIONS (Continued)

Table 6 contains the Variable O&M and Fixed Costs that are derived from a natural gas-fired CCCT. (C)

TABLE 6
Variable O&M, Fixed Costs and Gas Transportation Forecast - VFG ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2013	13.95	13.95	13.92	13.81	13.80	13.82	13.83	13.84	13.84	13.85	13.89	13.93
2014	14.15	14.15	14.12	14.02	14.01	14.02	14.03	14.04	14.05	14.06	14.09	14.13
2015	14.34	14.34	14.31	14.21	14.21	14.22	14.23	14.24	14.24	14.25	14.28	14.32
2016	14.56	14.56	14.52	14.43	14.42	14.43	14.44	14.45	14.46	14.47	14.50	14.53
2017	14.87	14.86	14.83	14.74	14.73	14.74	14.75	14.76	14.76	14.78	14.81	14.84
2018	15.18	15.18	15.15	15.04	15.04	15.05	15.06	15.07	15.07	15.09	15.12	15.16
2019	15.53	15.53	15.49	15.38	15.37	15.38	15.40	15.41	15.41	15.42	15.46	15.50
2020	15.76	15.76	15.73	15.62	15.61	15.62	15.64	15.65	15.65	15.66	15.70	15.74
2021	16.10	16.10	16.06	15.95	15.95	15.96	15.97	15.98	15.99	16.00	16.03	16.08
2022	16.41	16.41	16.38	16.26	16.25	16.27	16.28	16.29	16.29	16.31	16.34	16.39
2023	16.76	16.76	16.72	16.60	16.59	16.60	16.62	16.63	16.64	16.65	16.69	16.73
2024	17.08	17.08	17.04	16.91	16.90	16.92	16.93	16.94	16.95	16.96	17.00	17.05
2025	17.44	17.44	17.39	17.27	17.26	17.27	17.29	17.30	17.30	17.32	17.36	17.41
2026	17.77	17.77	17.72	17.59	17.59	17.60	17.62	17.63	17.63	17.65	17.69	17.74
2027	18.11	18.10	18.06	17.93	17.92	17.93	17.95	17.96	17.97	17.98	18.02	18.07
2028	18.41	18.41	18.37	18.23	18.22	18.24	18.25	18.27	18.27	18.29	18.33	18.38

(C)
(C)

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD CONTRACTS (Continued)
MARKET BASED PRICE OPTIONS (Continued)

Table 7 represents the variable C in the formulas for Option 2 (Deadband Index Gas Price Option) and Option 3 (Index Gas Price Option).

TABLE 7
Capacity Value - C ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
2013	32.77	32.77	32.77	32.77	32.77	32.77	32.77	32.77	32.77	32.77	32.77	32.77	(C)
2014	33.40	33.40	33.40	33.40	33.40	33.40	33.40	33.40	33.40	33.40	33.40	33.40	
2015	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03	
2016	34.57	34.57	34.57	34.57	34.57	34.57	34.57	34.57	34.57	34.57	34.57	34.57	
2017	35.45	35.45	35.45	35.45	35.45	35.45	35.45	35.45	35.45	35.45	35.45	35.45	
2018	36.01	36.01	36.01	36.01	36.01	36.01	36.01	36.01	36.01	36.01	36.01	36.01	
2019	36.69	36.69	36.69	36.69	36.69	36.69	36.69	36.69	36.69	36.69	36.69	36.69	
2020	37.27	37.27	37.27	37.27	37.27	37.27	37.27	37.27	37.27	37.27	37.27	37.27	
2021	38.10	38.10	38.10	38.10	38.10	38.10	38.10	38.10	38.10	38.10	38.10	38.10	
2022	38.82	38.82	38.82	38.82	38.82	38.82	38.82	38.82	38.82	38.82	38.82	38.82	
2023	39.69	39.69	39.69	39.69	39.69	39.69	39.69	39.69	39.69	39.69	39.69	39.69	
2024	40.18	40.18	40.18	40.18	40.18	40.18	40.18	40.18	40.18	40.18	40.18	40.18	
2025	41.08	41.08	41.08	41.08	41.08	41.08	41.08	41.08	41.08	41.08	41.08	41.08	
2026	41.86	41.86	41.86	41.86	41.86	41.86	41.86	41.86	41.86	41.86	41.86	41.86	
2027	42.65	42.65	42.65	42.65	42.65	42.65	42.65	42.65	42.65	42.65	42.65	42.65	
2028	43.46	43.46	43.46	43.46	43.46	43.46	43.46	43.46	43.46	43.46	43.46	43.46	(C)

SCHEDULE 201 (Continued)

MONTHLY SERVICE CHARGE (M)

Each separately metered QF not associated with a retail Customer account will be charged $10.00 per month.

INSURANCE REQUIREMENTS

The following insurance requirements are applicable to Sellers with a Standard Contract:

1) QFs with nameplate capacity ratings greater than 200 kW are required to secure and maintain a prudent amount of general liability insurance. The Seller must certify to the Company that it is maintaining general liability insurance coverage for each QF at prudent amounts. A prudent amount will be deemed to mean liability insurance coverage for both bodily injury and property damage liability in the amount of not less than $1,000,000 each occurrence combined single limit, which limits may be required to be increased or decreased by the Company as the Company determines in its reasonable judgment economic conditions or claims experience may warrant.

2) Such insurance will include an endorsement naming the Company as an additional insured insofar as liability arising out of operations under this schedule and a provision that such liability policies will not be canceled or their limits reduced without 30 days' written notice to the Company. The Seller will furnish the Company with certificates of insurance together with the endorsements required herein. The Company will have the right to inspect the original policies of such insurance.

3) QFs with a design capacity of 200 kW or less are encouraged to pursue liability insurance on his/her own. The Oregon Public Utility Commission in Order No. 05-584 determined that it is inappropriate to require QFs that have a design capacity of 200 kW or less to obtain general liability insurance.

TRANSMISSION AGREEMENTS

If the QF is located outside the Company's service territory, the Seller is responsible for the transmission of power at its cost to the Company's service territory.

INTERCONNECTION REQUIREMENTS

Except as otherwise provided in a generation Interconnection Agreement between the Company and Seller, if the QF is located within the Company's service territory, switching equipment capable of isolating the QF from the Company's system will be accessible to the Company at all times. At the Company's option, the Company may operate the switching equipment described above if, in the sole opinion of the Company, continued operation of the QF in connection with the utility's system may create or contribute to a system emergency. (M)

SCHEDULE 201 (Continued)

INTERCONNECTION REQUIREMENTS (Continued) **(M)**

The QF owner interconnecting with the Company's distribution system must comply with all requirements for interconnection as established pursuant to Commission rule, in the Company's **(C)** Rules and Regulations (Rule C) or the Company's Interconnection Procedures contained in its **(C)** FERC Open Access Transmission Tariff (OATT), as applicable. The Seller will bear full responsibility for the installation and safe operation of the interconnection facilities.

DEFINITION OF A SMALL COGENERATION FACILITY OR SMALL POWER PRODUCTION FACILITY ELIGIBLE TO RECEIVE THE STANDARD RATES AND STANDARD CONTRACT

A QF will be eligible to receive the standard rates and Standard Contract if the nameplate capacity of the QF, together with any other electric generating facility using the same motive force, owned or controlled by the same person(s) or affiliated person(s), and located at the same site, does not exceed 10 MW.

Definition of Person(s) or Affiliated Person(s)

As used above, the term "same person(s)" or "affiliated person(s)" means a natural person or persons or any legal entity or entities sharing common ownership, management or acting jointly or in concert with or exercising influence over the policies or actions of another person or entity. However, two facilities will not be held to be owned or controlled by the same person(s) or affiliated person(s) solely because they are developed by a single entity.

Furthermore, two facilities will not be held to be owned or controlled by the same person(s) or affiliated person(s) if such common person or persons is a "passive investor" whose ownership interest in the QF is primarily related to utilizing production tax credits, green tag values and MACRS depreciation as the primary ownership benefit. A unit of Oregon local government may also be a "passive investor" if the local governmental unit demonstrates that it will not have an equity ownership interest in or exercise any control over the management of the QF and that its only interest is a share of the cash flow from the QF, which share will not exceed 20%. The 20% cash flow share limit may only be exceeded for good cause shown and only with the prior approval of the Commission.

Definition of Same Site

For purposes of the foregoing, generating facilities are considered to be located at the same site as the QF for which qualification for the standard rates and Standard Contract is sought if they are located within a five-mile radius of any generating facilities or equipment providing fuel or motive force associated with the QF for which qualification for the standard rates and standard contract is sought. **(M)**

SCHEDULE 201 (Concluded) (T)

DEFINITION OF A SMALL COGENERATION FACILITY OR SMALL POWER PRODUCTION FACILITY ELIGIBLE TO RECEIVE THE STANDARD RATES AND STANDARD CONTRACT (Continued) (M)

Shared Interconnection and Infrastructure

QFs otherwise meeting the above-described separate ownership test and thereby qualified for entitlement to the standard rates and Standard Contract will not be disqualified by utilizing an interconnection or other infrastructure not providing motive force or fuel that is shared with other QFs qualifying for the standard rates and Standard Contract so long as the use of the shared interconnection complies with the interconnecting utility's safety and reliability standards, interconnection contract requirements and Prudent Electrical Practices as that term is defined in the interconnecting utility's approved Standard Contract.

Dispute Resolution

Upon request, the QF will provide the purchasing utility with documentation verifying the ownership, management and financial structure of the QF in reasonably sufficient detail to allow the utility to make an initial determination of whether or not the QF meets the above-described criteria for entitlement to the standard rates and Standard Contract. Any dispute concerning a QF's entitlement to the standard rates and Standard Contract will be presented (T) to the Commission for resolution.

SPECIAL CONDITIONS

1. Delivery of energy by Seller will be at a voltage, phase, frequency, and power factor as specified by the Company.

2. If the Seller also receives retail Electricity Service from the Company at the same location, any payments under this schedule will be credited to the Seller's retail Electricity Service bill. At the option of the Customer, any net credit over $10.00 will be paid by check to the Customer.

3. Contracts entered into pursuant to this schedule will not terminate prior to the Standard or negotiated contract's termination date if the 1978 Public Utility Regulatory Policies Act (PURPA) is repealed.

TERM OF AGREEMENT

Not less than one year and not to exceed 20 years. (M)

PGE Advice No. 09-16
Work Papers

PORTLAND GENERAL ELECTRIC COMPANY
2009 AVOIDED COST STUDY

Introduction

Federal regulations require Portland General Electric Company (PGE or the Company) to "maintain for public inspection ... the estimated avoided cost on the electric utility's system" [18 Code of Federal Regulations (CFR) Part 292.302]. In addition, OPUC Order No. 05-584 specifies a methodology for calculating a twenty year projection of avoided costs. This study conforms to OPUC guidelines regarding the presentation and calculation of these costs. It describes the data and assumptions PGE uses to estimate avoided costs, and documents the forward curve and proxy plant estimates for a Qualifying Facility (QF) purchase agreement.

"Avoided costs mean the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source" [18 CFR Part 292.101(b)(6)]. Avoided costs reflect projections of year-by-year PGE avoided system costs. As explained in OAR 860-29-0005(3)(d), actual avoided costs "will depend on the quality and quantity of power to be delivered to the utility" and "may be recalculated to reflect stream flows, generating unit availability, loads, seasons, and other conditions." The price at which PGE will purchase power produced by a QF depends on PGE's actual avoided cost for power and the nature of the contractual obligation between PGE and the QF. Changes in PGE's resource needs and the cost of resource alternatives during negotiations can affect the price PGE pays.

Integrated Resource Plan

The Company's current Integrated Resource Plan (IRP) under development forms the basis for this study. The IRP process to date has included five public meetings with an additional one to two remaining. PGE is required to file this IRP with the Commission by November, 2009 although we anticipate filing a draft IRP sooner.

The basis for this study is the Company's Integrated Resource Plan (IRP), to be filed in the ongoing proceeding which will be reviewed by the OPUC in conjunction with the avoided cost methodology outlined by Commission Order 05-584.

Avoided Cost Estimates

Tables 1 through 5 (following) summarize PGE avoided cost data consistent with Commission Order 05-584. Tables 1 and 2 are estimates of monthly on- and off-peak avoided costs for energy and capacity for twenty years beginning August 2009 and ending

December 2028. The prices (expressed in $/MWh or mills/kWh) for the years 2009 through 2012, are based on forward curves, and represent capacity and energy avoided costs. On-peak prices for 2013 to 2028 are represented by capacity and energy costs, while off-peak prices are represented by energy costs only. The on-peak price includes the following costs of a CCCT: fuel, variable O&M, capacity, and other fixed costs. The off-peak price includes: fuel, variable O&M, and other fixed costs. The "other fixed costs" represent the energy portion of the fixed costs of a CCCT. Other fixed costs are calculated by taking the fixed costs of a CCCT minus the real levelized capital carrying cost and fixed O&M of an SCCT. The result (other fixed costs) represents the energy portion of the fixed costs of a CCCT. On-peak periods are from 6 a.m. through 10 p.m. Mondays through Saturdays. The off-peak hours are from 10 p.m. until 6 a.m. Mondays through Saturdays and all twenty-four hours on Sunday. Table 3 provides flat monthly avoided costs, and Tables 4 and 5 show the on- and off-peak resource sufficiency rates.

Resource Timing

Order No. 05-584 states that during resource sufficiency periods, a utility is required to use forward market curves as the basis for the avoided resource. When a utility is resource deficient, avoided energy and capacity values are based on the costs of a proxy generation plant. Based on the current, in-progress IRP analysis, avoided costs are based on adding a resource in 2013. During the resource sufficiency time frame, from 2009 to 2012, the avoided resource is based on a forward curve. From 2013 through 2028, total avoided costs are based on costs of a combined cycle combustion turbine (CCCT). Avoided capacity costs are based on the fixed costs of a single-cycle combustion turbine (SCCT). Both the SCCT and CCCT costs are developed using the financial parameters listed on Table 15.

PGE's current IRP analysis supports the resource addition in 2013. Until at least that time PGE will use market purchases to meet both capacity and energy needs. See Charts A and B, depicting PGE's load/resource balance[1]. The resources shown include PGE owned generation, contracts, and energy from renewable RFP. Market purchases are not included. Avoided costs reflect short to mid-term market purchases which will be used to balance load and resources through 2012.

Market purchases are forecast to be available in the region through at least 2013. The Northwest Power and Conservation Council's Power Supply Outlook Update from February 2009 indicates, "The likelihood of a significant power shortage over the next five years due to an inadequate supply continues to be minimal. Based on the 2008 Assessment the region's annual supply of energy from existing sources is projected to be about 1,900 average megawatts over the minimum adequacy threshold by 2013." The update also

1 Charts A and B are from PGE's Integrated Resource Plan 2009 Fifth Stakeholder Presentation and Discussion held on May 19, 2009

states, "By 2013 summer surplus peaking capacity is projected to be 1,400 megawatts over the minimum threshold."

CO2 (Carbon) Regulation

The Company, as directed in Order No. 08-339 is evaluating expected regulatory compliance for CO2 in our ongoing IRP. No assumptions are made at this point as to cost effects of CO2 regulation.

Gas Price Projections

The basis for the gas prices used in this study is the average of the forecasted AECO and Sumas gas prices, adjusted for transportation costs. Monthly gas forecasts through 2024 were developed using annual price forecast from PIRA Energy Group (PIRA) and include monthly shaping factors based on recent NYMEX prices. For a PGE specific gas index both the AECO and Sumas trading hubs were used, each with individual PIRA forecasts. Prices for 2025 and beyond were extrapolated from the PIRA 2024 forecasts escalated at an assumed inflation rate.

The nominal average northwest burnertip natural gas price is expected to trend from \$6.86/MMBtu in 2013 to \$8.77/MMBtu in 2028. In order to simplify market-based pricing, the estimate of gas transportation costs is fixed. The heat rate of a CCCT is then applied to the estimated transportation costs for both the AECO and Sumas trading hubs. This gas transportation estimate is added to the fixed costs and variable O&M costs to calculate Table 6 in Schedule 201.

Avoided Cost Components

Tables 6 through 14 in the work papers show the capacity, fixed, variable, and gas forecast avoided cost components. The on- and off-peak SCCT-related capacity component costs are shown in Tables 6 and 7. The capacity values are applicable to on-peak hours. Table 8 contains the energy portion of a CCCT, calculated using fixed costs of a CCCT minus the real levelized capital carrying cost and fixed O&M of an SCCT. Table 9 shows the variable O&M associated with the CCCT and Table 10 shows the projected fuel costs. Table 11 contains the forecasted gas prices in \$/MMbtu and Table 12 shows the variable O&M, fixed costs and gas transportation forecast . Tables 13 and 14 are the AECO and Sumas gas forecasts. Tables 6, 8, 9 and 10 can be summed to equal the total on-peak avoided costs in Table 1. Tables 7, 8, 9 and 10 can be summed to equal the total off-peak avoided costs in Table 2.

Financial Parameters

The Cost of Capital and related economic assumptions are listed on Table 15. These have been used for SCCT and CCCT costs and are consistent with the IRP.

Portland General Electric
Avoided Cost Study
Total Projected On Peak Avoided Costs

Table 1

Nominal $/MWh

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2009								32.71	31.59	32.46	41.21	50.34
2010	51.25	47.75	42.75	41.00	36.00	33.25	53.75	58.25	57.75	53.75	56.00	59.25
2011	60.30	56.80	53.55	47.55	40.80	39.55	64.05	66.80	63.55	58.80	62.05	65.05
2012	62.07	57.81	51.71	49.58	43.48	40.13	65.12	70.61	70.00	65.12	67.86	71.83
2013	97.44	97.41	95.83	90.96	90.67	91.16	91.72	92.21	92.38	92.90	94.45	96.26
2014	96.31	96.28	94.76	90.04	89.79	90.26	90.83	91.27	91.46	91.99	93.47	95.24
2015	94.54	94.51	93.07	88.60	88.36	88.81	89.35	89.76	89.94	90.45	91.85	93.52
2016	94.77	94.74	93.32	88.90	88.66	89.11	89.64	90.05	90.23	90.73	92.12	93.77
2017	97.00	96.97	95.52	90.99	90.75	91.21	91.75	92.17	92.35	92.86	94.28	95.97
2018	100.22	100.19	98.67	93.92	93.66	94.14	94.71	95.15	95.34	95.88	97.37	99.15
2019	104.73	104.70	103.07	97.98	97.71	98.22	98.83	99.30	99.51	100.08	101.68	103.58
2020	105.39	105.35	103.73	98.65	98.38	98.89	99.50	99.97	100.17	100.75	102.34	104.23
2021	107.84	107.81	106.14	100.94	100.67	101.19	101.81	102.29	102.50	103.09	104.72	106.66
2022	110.17	110.13	108.43	103.10	102.82	103.35	103.99	104.49	104.70	105.30	106.97	108.96
2023	113.96	113.92	112.13	106.56	106.26	106.82	107.49	108.01	108.23	108.86	110.61	112.69
2024	117.35	117.31	115.45	109.62	109.31	109.89	110.59	111.13	111.37	112.03	113.85	116.03
2025	119.74	119.70	117.80	111.86	111.55	112.14	112.85	113.41	113.65	114.32	116.18	118.40
2026	122.01	121.97	120.04	113.99	113.66	114.27	115.00	115.56	115.80	116.49	118.38	120.64
2027	124.33	124.29	122.32	116.15	115.82	116.44	117.18	117.75	118.00	118.70	120.63	122.93
2028	126.65	126.61	124.60	118.32	117.98	118.61	119.37	119.95	120.20	120.91	122.88	125.23

Portland General Electric
Avoided Cost Study
Total Projected Off Peak Avoided Costs

Table 2

Nominal $/MWh

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2009								26.59	27.21	27.71	35.21	43.71
2010	44.75	42.75	37.75	34.75	26.25	23.75	40.25	44.00	41.75	42.75	48.75	55.25
2011	55.30	51.80	48.05	36.80	29.80	27.30	45.30	50.55	50.30	49.80	53.80	57.05
2012	53.00	50.62	44.66	41.08	30.95	27.97	47.64	52.11	49.42	50.62	57.77	65.52
2013	64.67	64.64	63.06	58.19	57.89	58.39	58.94	59.44	59.60	60.13	61.68	63.49
2014	62.91	62.88	61.37	56.64	56.39	56.86	57.43	57.87	58.06	58.60	60.08	61.84
2015	60.51	60.48	59.04	54.57	54.33	54.78	55.32	55.73	55.91	56.42	57.82	59.49
2016	60.20	60.17	58.76	54.33	54.10	54.54	55.07	55.48	55.66	56.16	57.55	59.20
2017	61.55	61.52	60.07	55.55	55.30	55.76	56.30	56.72	56.90	57.42	58.83	60.52
2018	64.22	64.19	62.66	57.91	57.66	58.13	58.70	59.15	59.34	59.88	61.37	63.14
2019	68.04	68.01	66.38	61.29	61.02	61.53	62.14	62.61	62.82	63.39	64.99	66.89
2020	68.12	68.08	66.46	61.38	61.11	61.62	62.23	62.70	62.91	63.48	65.07	66.97
2021	69.74	69.71	68.04	62.84	62.57	63.09	63.71	64.20	64.40	64.99	66.62	68.56
2022	71.34	71.31	69.60	64.28	63.99	64.53	65.17	65.66	65.88	66.48	68.15	70.14
2023	74.27	74.23	72.45	66.87	66.57	67.13	67.80	68.32	68.54	69.18	70.92	73.01
2024	77.17	77.13	75.26	69.44	69.12	69.71	70.41	70.95	71.18	71.84	73.67	75.84
2025	78.66	78.62	76.72	70.79	70.47	71.06	71.78	72.33	72.57	73.24	75.10	77.32
2026	80.16	80.12	78.18	72.13	71.81	72.41	73.14	73.70	73.94	74.63	76.53	78.78
2027	81.68	81.64	79.66	73.50	73.17	73.78	74.52	75.10	75.35	76.04	77.98	80.28
2028	83.19	83.15	81.14	74.85	74.52	75.15	75.90	76.49	76.74	77.45	79.42	81.77

Portland General Electric
Avoided Cost Study
Total Projected Average Avoided Costs

Table 3

Nominal $/MWh

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2009								30.01	29.74	30.47	38.54	47.56
2010	48.39	45.61	40.66	38.36	31.70	29.24	48.09	51.97	51.00	48.90	52.94	57.58
2011	58.09	54.65	51.24	43.01	35.95	34.37	55.78	59.98	57.95	54.83	58.56	61.69
2012	58.07	54.75	48.75	45.80	38.23	35.00	57.41	62.85	60.85	59.04	63.60	69.05
2013	83.70	83.36	81.38	77.12	76.92	76.59	77.97	78.47	77.81	79.16	80.61	81.81
2014	82.30	81.96	80.04	75.94	75.78	75.42	76.82	76.54	77.36	77.99	78.63	81.23
2015	80.27	79.92	78.07	74.23	73.36	74.44	75.08	74.76	75.58	76.18	76.73	79.25
2016	79.53	80.04	78.83	74.31	73.43	74.51	74.40	75.56	75.63	75.49	77.52	79.27
2017	81.37	81.77	80.65	75.24	75.89	76.24	76.12	77.31	77.38	77.24	79.31	80.34
2018	85.12	84.76	83.57	77.92	78.57	78.94	78.84	80.05	79.34	80.78	82.17	83.27
2019	89.35	88.98	86.90	82.49	82.32	81.91	83.44	83.92	83.20	84.70	86.19	87.40
2020	89.76	89.50	87.30	82.92	81.95	83.15	83.87	83.54	84.44	85.12	85.78	88.61
2021	91.05	91.48	90.17	84.86	83.87	85.10	85.83	85.50	86.42	86.30	88.64	90.69
2022	93.05	93.49	92.15	86.71	85.70	86.96	86.87	88.21	88.31	88.19	90.58	92.68
2023	96.46	96.91	95.49	88.92	89.62	90.06	89.99	91.37	91.47	91.37	93.85	95.20
2024	100.50	100.22	97.73	92.65	92.46	92.03	93.74	94.28	93.51	95.18	96.89	98.31
2025	102.52	102.10	99.69	94.52	94.32	93.88	95.63	95.30	96.30	97.09	97.92	101.17
2026	104.46	104.03	101.58	96.31	95.21	96.60	97.44	97.11	98.13	98.93	99.78	103.09
2027	105.53	106.01	104.43	98.14	97.02	98.43	99.29	98.95	99.99	99.89	102.62	105.05
2028	107.49	108.13	106.37	99.00	99.76	100.26	100.20	101.72	101.85	101.75	104.53	106.07

Portland General Electric
Avoided Cost Study
Projected On Peak Resource Sufficiency Period Forward Market Prices

Table 4

Nominal $/MWh

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2009								32.71	31.59	32.46	41.21	50.34
2010	51.25	47.75	42.75	41.00	36.00	33.25	53.75	58.25	57.75	53.75	56.00	59.25
2011	60.30	56.80	53.55	47.55	40.80	39.55	64.05	66.80	63.55	58.80	62.05	65.05
2012	62.07	57.81	51.71	49.58	43.48	40.13	65.12	70.61	70.00	65.12	67.86	71.83

Portland General Electric
Avoided Cost Study
Projected Off Peak Resource Sufficiency Period Forward Market Prices

Table 5

Nominal $/MWh

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2009								26.59	27.21	27.71	35.21	43.71
2010	44.75	42.75	37.75	34.75	26.25	23.75	40.25	44.00	41.75	42.75	48.75	55.25
2011	55.30	51.80	48.05	36.80	29.80	27.30	45.30	50.55	50.30	49.80	53.80	57.05
2012	53.00	50.62	44.66	41.08	30.95	27.97	47.64	52.11	49.42	50.62	57.77	65.52

Portland General Electric
Avoided Cost Study
Total Projected On Peak Avoided Capacity Costs

Table 6

Nominal $/MWh

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2009												
2010												
2011												
2012												
2013	32.77	32.77	32.77	32.77	32.77	32.77	32.77	32.77	32.77	32.77	32.77	32.77
2014	33.40	33.40	33.40	33.40	33.40	33.40	33.40	33.40	33.40	33.40	33.40	33.40
2015	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03
2016	34.57	34.57	34.57	34.57	34.57	34.57	34.57	34.57	34.57	34.57	34.57	34.57
2017	35.45	35.45	35.45	35.45	35.45	35.45	35.45	35.45	35.45	35.45	35.45	35.45
2018	36.01	36.01	36.01	36.01	36.01	36.01	36.01	36.01	36.01	36.01	36.01	36.01
2019	36.69	36.69	36.69	36.69	36.69	36.69	36.69	36.69	36.69	36.69	36.69	36.69
2020	37.27	37.27	37.27	37.27	37.27	37.27	37.27	37.27	37.27	37.27	37.27	37.27
2021	38.10	38.10	38.10	38.10	38.10	38.10	38.10	38.10	38.10	38.10	38.10	38.10
2022	38.82	38.82	38.82	38.82	38.82	38.82	38.82	38.82	38.82	38.82	38.82	38.82
2023	39.69	39.69	39.69	39.69	39.69	39.69	39.69	39.69	39.69	39.69	39.69	39.69
2024	40.18	40.18	40.18	40.18	40.18	40.18	40.18	40.18	40.18	40.18	40.18	40.18
2025	41.08	41.08	41.08	41.08	41.08	41.08	41.08	41.08	41.08	41.08	41.08	41.08
2026	41.86	41.86	41.86	41.86	41.86	41.86	41.86	41.86	41.86	41.86	41.86	41.86
2027	42.65	42.65	42.65	42.65	42.65	42.65	42.65	42.65	42.65	42.65	42.65	42.65
2028	43.46	43.46	43.46	43.46	43.46	43.46	43.46	43.46	43.46	43.46	43.46	43.46

Portland General Electric
Avoided Cost Study
Total Projected Off Peak Avoided Capacity Costs

Table 7

Nominal $/MWh

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2009												
2010												
2011												
2012												
2013	-	-	-	-	-	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-	-	-	-	-	-
2017	-	-	-	-	-	-	-	-	-	-	-	-
2018	-	-	-	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-	-	-	-
2020	-	-	-	-	-	-	-	-	-	-	-	-
2021	-	-	-	-	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-	-

Portland General Electric
Avoided Cost Study
Total Projected Other Fixed Avoided Costs

Table 8

Nominal $/MWh

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2009												
2010												
2011												
2012												
2013	10.03	10.03	10.03	10.03	10.03	10.03	10.03	10.03	10.03	10.03	10.03	10.03
2014	10.22	10.22	10.22	10.22	10.22	10.22	10.22	10.22	10.22	10.22	10.22	10.22
2015	10.41	10.41	10.41	10.41	10.41	10.41	10.41	10.41	10.41	10.41	10.41	10.41
2016	10.58	10.58	10.58	10.58	10.58	10.58	10.58	10.58	10.58	10.58	10.58	10.58
2017	10.81	10.81	10.81	10.81	10.81	10.81	10.81	10.81	10.81	10.81	10.81	10.81
2018	11.02	11.02	11.02	11.02	11.02	11.02	11.02	11.02	11.02	11.02	11.02	11.02
2019	11.23	11.23	11.23	11.23	11.23	11.23	11.23	11.23	11.23	11.23	11.23	11.23
2020	11.41	11.41	11.41	11.41	11.41	11.41	11.41	11.41	11.41	11.41	11.41	11.41
2021	11.66	11.66	11.66	11.66	11.66	11.66	11.66	11.66	11.66	11.66	11.66	11.66
2022	11.88	11.88	11.88	11.88	11.88	11.88	11.88	11.88	11.88	11.88	11.88	11.88
2023	12.11	12.11	12.11	12.11	12.11	12.11	12.11	12.11	12.11	12.11	12.11	12.11
2024	12.30	12.30	12.30	12.30	12.30	12.30	12.30	12.30	12.30	12.30	12.30	12.30
2025	12.57	12.57	12.57	12.57	12.57	12.57	12.57	12.57	12.57	12.57	12.57	12.57
2026	12.81	12.81	12.81	12.81	12.81	12.81	12.81	12.81	12.81	12.81	12.81	12.81
2027	13.05	13.05	13.05	13.05	13.05	13.05	13.05	13.05	13.05	13.05	13.05	13.05
2028	13.27	13.27	13.27	13.27	13.27	13.27	13.27	13.27	13.27	13.27	13.27	13.27

Portland General Electric
Avoided Cost Study
Total Projected Avoided Variable O&M Costs

Table 9

Nominal $/MWh

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2009												
2010												
2011												
2012												
2013	2.80	2.80	2.80	2.80	2.80	2.80	2.80	2.80	2.80	2.80	2.80	2.80
2014	2.85	2.85	2.85	2.85	2.85	2.85	2.85	2.85	2.85	2.85	2.85	2.85
2015	2.91	2.91	2.91	2.91	2.91	2.91	2.91	2.91	2.91	2.91	2.91	2.91
2016	2.96	2.96	2.96	2.96	2.96	2.96	2.96	2.96	2.96	2.96	2.96	2.96
2017	3.02	3.02	3.02	3.02	3.02	3.02	3.02	3.02	3.02	3.02	3.02	3.02
2018	3.08	3.08	3.08	3.08	3.08	3.08	3.08	3.08	3.08	3.08	3.08	3.08
2019	3.13	3.13	3.13	3.13	3.13	3.13	3.13	3.13	3.13	3.13	3.13	3.13
2020	3.19	3.19	3.19	3.19	3.19	3.19	3.19	3.19	3.19	3.19	3.19	3.19
2021	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25
2022	3.32	3.32	3.32	3.32	3.32	3.32	3.32	3.32	3.32	3.32	3.32	3.32
2023	3.38	3.38	3.38	3.38	3.38	3.38	3.38	3.38	3.38	3.38	3.38	3.38
2024	3.44	3.44	3.44	3.44	3.44	3.44	3.44	3.44	3.44	3.44	3.44	3.44
2025	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51
2026	3.58	3.58	3.58	3.58	3.58	3.58	3.58	3.58	3.58	3.58	3.58	3.58
2027	3.64	3.64	3.64	3.64	3.64	3.64	3.64	3.64	3.64	3.64	3.64	3.64
2028	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71

Portland General Electric
Avoided Cost Study
Total Projected Avoided Fuel Costs

Table 10

Nominal $/MWh

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2009												
2010												
2011												
2012												
2013	51.84	51.81	50.23	45.36	45.06	45.56	46.12	46.61	46.77	47.30	48.85	50.66
2014	49.84	49.81	48.30	43.57	43.32	43.79	44.36	44.80	44.99	45.52	47.00	48.77
2015	47.18	47.15	45.72	41.25	41.01	41.46	41.99	42.41	42.59	43.10	44.50	46.17
2016	46.66	46.63	45.21	40.79	40.55	41.00	41.53	41.94	42.12	42.62	44.00	45.65
2017	47.72	47.69	46.24	41.71	41.47	41.92	42.47	42.89	43.07	43.58	45.00	46.69
2018	50.12	50.09	48.57	43.82	43.56	44.04	44.61	45.05	45.24	45.78	47.27	49.04
2019	53.68	53.65	52.02	46.93	46.65	47.16	47.77	48.25	48.45	49.03	50.63	52.53
2020	53.51	53.48	51.85	46.78	46.51	47.01	47.62	48.10	48.30	48.88	50.47	52.36
2021	54.83	54.79	53.13	47.93	47.65	48.17	48.80	49.28	49.49	50.08	51.71	53.65
2022	56.15	56.11	54.41	49.08	48.80	49.33	49.97	50.47	50.68	51.28	52.95	54.94
2023	58.78	58.75	56.96	51.38	51.09	51.64	52.31	52.83	53.06	53.69	55.44	57.52
2024	61.42	61.38	59.52	53.69	53.38	53.96	54.66	55.20	55.44	56.10	57.92	60.10
2025	62.58	62.54	60.64	54.71	54.39	54.98	55.70	56.25	56.49	57.16	59.02	61.24
2026	63.77	63.73	61.79	55.74	55.42	56.02	56.75	57.32	57.56	58.24	60.14	62.40
2027	64.98	64.94	62.96	56.80	56.47	57.09	57.83	58.40	58.65	59.35	61.28	63.58
2028	66.21	66.17	64.16	57.88	57.54	58.17	58.92	59.51	59.76	60.47	62.44	64.79

Portland General Electric
Avoided Cost Study
Forecasted Gas Price - GPf ($/Mmbtu - without transportation)

Table 11

Nominal $/MMbtu

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2009												
2010												
2011												
2012												
2013	7.413	7.408	7.182	6.484	6.441	6.512	6.592	6.663	6.686	6.762	6.983	7.243
2014	7.126	7.121	6.905	6.227	6.191	6.259	6.340	6.403	6.430	6.507	6.719	6.972
2015	6.745	6.741	6.536	5.894	5.860	5.924	6.001	6.061	6.087	6.159	6.360	6.600
2016	6.670	6.665	6.463	5.828	5.795	5.858	5.934	5.993	6.019	6.090	6.289	6.526
2017	6.821	6.817	6.610	5.961	5.926	5.991	6.069	6.130	6.155	6.229	6.432	6.674
2018	7.166	7.162	6.944	6.262	6.226	6.294	6.376	6.440	6.467	6.544	6.757	7.012
2019	7.676	7.672	7.438	6.708	6.669	6.742	6.830	6.898	6.927	7.010	7.239	7.511
2020	7.652	7.647	7.415	6.687	6.648	6.721	6.808	6.876	6.905	6.988	7.216	7.487
2021	7.841	7.836	7.598	6.852	6.812	6.887	6.976	7.046	7.076	7.160	7.394	7.672
2022	8.030	8.025	7.781	7.017	6.976	7.053	7.144	7.216	7.246	7.333	7.572	7.857
2023	8.408	8.403	8.147	7.347	7.305	7.385	7.481	7.555	7.587	7.678	7.928	8.227
2024	8.786	8.780	8.513	7.678	7.633	7.717	7.817	7.895	7.928	8.023	8.285	8.596
2025	8.953	8.947	8.675	7.823	7.778	7.863	7.965	8.045	8.079	8.175	8.442	8.760
2026	9.123	9.117	8.840	7.972	7.926	8.013	8.117	8.198	8.232	8.331	8.602	8.926
2027	9.296	9.290	9.007	8.124	8.076	8.165	8.271	8.353	8.389	8.489	8.766	9.096
2028	9.473	9.467	9.179	8.278	8.230	8.320	8.428	8.512	8.548	8.650	8.932	9.269

Portland General Electric
Avoided Cost Study
Variable O&M, Fixed Costs and Gas Transportation Forecast - VFG ($/MWH)

Table 12

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2009												
2010												
2011												
2012												
2013	13.95	13.95	13.92	13.81	13.80	13.82	13.83	13.84	13.84	13.85	13.89	13.93
2014	14.15	14.15	14.12	14.02	14.01	14.02	14.03	14.04	14.05	14.06	14.09	14.13
2015	14.34	14.34	14.31	14.21	14.21	14.22	14.23	14.24	14.24	14.25	14.28	14.32
2016	14.56	14.56	14.52	14.43	14.42	14.43	14.44	14.45	14.46	14.47	14.50	14.53
2017	14.87	14.86	14.83	14.74	14.73	14.74	14.75	14.76	14.76	14.78	14.81	14.84
2018	15.18	15.18	15.15	15.04	15.04	15.05	15.06	15.07	15.07	15.09	15.12	15.16
2019	15.53	15.53	15.49	15.38	15.37	15.38	15.40	15.41	15.41	15.42	15.46	15.50
2020	15.76	15.76	15.73	15.62	15.61	15.62	15.64	15.65	15.65	15.66	15.70	15.74
2021	16.10	16.10	16.06	15.95	15.95	15.96	15.97	15.98	15.99	16.00	16.03	16.08
2022	16.41	16.41	16.38	16.26	16.25	16.27	16.28	16.29	16.29	16.31	16.34	16.39
2023	16.76	16.76	16.72	16.60	16.59	16.60	16.62	16.63	16.64	16.65	16.69	16.73
2024	17.08	17.08	17.04	16.91	16.90	16.92	16.93	16.94	16.95	16.96	17.00	17.05
2025	17.44	17.44	17.39	17.27	17.26	17.27	17.29	17.30	17.30	17.32	17.36	17.41
2026	17.77	17.77	17.72	17.59	17.59	17.60	17.62	17.63	17.63	17.65	17.69	17.74
2027	18.11	18.10	18.06	17.93	17.92	17.93	17.95	17.96	17.97	17.98	18.02	18.07
2028	18.41	18.41	18.37	18.23	18.22	18.24	18.25	18.27	18.27	18.29	18.33	18.38

Portland General Electric Company
Avoided Cost Study
AECO Gas Price Forecast

Table 13

AECO Gas Price ($/MMBtu - Nominal$)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
2013	7.328	7.324	7.100	6.410	6.368	6.438	6.517	6.587	6.610	6.685	6.904	7.161	6.786
2014	7.045	7.040	6.826	6.156	6.120	6.187	6.268	6.330	6.357	6.433	6.643	6.893	6.525
2015	6.651	6.647	6.444	5.812	5.778	5.841	5.917	5.976	6.002	6.073	6.271	6.507	6.160
2016	6.575	6.571	6.371	5.746	5.712	5.775	5.850	5.908	5.933	6.004	6.200	6.434	6.090
2017	6.763	6.759	6.553	5.910	5.876	5.940	6.017	6.077	6.103	6.176	6.377	6.617	6.264
2018	7.126	7.121	6.905	6.227	6.191	6.259	6.340	6.403	6.430	6.507	6.719	6.972	6.600
2019	7.634	7.629	7.397	6.671	6.632	6.705	6.792	6.860	6.889	6.971	7.198	7.469	7.071
2020	7.521	7.516	7.287	6.572	6.534	6.606	6.691	6.758	6.787	6.868	7.092	7.359	6.966
2021	7.707	7.702	7.467	6.735	6.695	6.769	6.857	6.925	6.954	7.037	7.267	7.541	7.138
2022	7.892	7.887	7.647	6.897	6.857	6.932	7.022	7.092	7.122	7.207	7.442	7.722	7.310
2023	8.264	8.259	8.007	7.221	7.180	7.258	7.352	7.426	7.457	7.546	7.792	8.086	7.654
2024	8.635	8.630	8.367	7.546	7.502	7.584	7.683	7.759	7.792	7.885	8.143	8.449	7.998
2025	8.799	8.794	8.526	7.689	7.645	7.728	7.829	7.907	7.940	8.035	8.297	8.610	8.150
2026	8.966	8.961	8.688	7.835	7.790	7.875	7.978	8.057	8.091	8.188	8.455	8.773	8.305
2027	9.137	9.131	8.853	7.984	7.938	8.025	8.129	8.210	8.245	8.343	8.616	8.940	8.463
2028	9.310	9.305	9.021	8.136	8.089	8.177	8.284	8.366	8.402	8.502	8.779	9.110	8.623
2029	9.487	9.481	9.193	8.291	8.242	8.333	8.441	8.525	8.561	8.663	8.946	9.283	8.787

Variable Transportation Cost ($/MMBtu) $0.006768 Losses 1.57%

Transportation Cost ($/MMBtu - Nominal$)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
2013	0.121	0.121	0.118	0.107	0.106	0.108	0.109	0.110	0.110	0.111	0.115	0.119	0.113
2014	0.117	0.117	0.114	0.103	0.103	0.104	0.105	0.106	0.106	0.107	0.111	0.115	0.109
2015	0.111	0.111	0.108	0.098	0.097	0.098	0.099	0.100	0.101	0.102	0.105	0.109	0.103
2016	0.110	0.110	0.106	0.097	0.096	0.097	0.098	0.099	0.100	0.101	0.104	0.107	0.102
2017	0.113	0.113	0.109	0.099	0.099	0.100	0.101	0.102	0.102	0.103	0.107	0.110	0.105
2018	0.118	0.118	0.115	0.104	0.104	0.105	0.106	0.107	0.107	0.109	0.112	0.116	0.110
2019	0.126	0.126	0.123	0.111	0.111	0.112	0.113	0.114	0.115	0.116	0.119	0.124	0.117
2020	0.124	0.124	0.121	0.110	0.109	0.110	0.112	0.113	0.113	0.114	0.118	0.122	0.116
2021	0.127	0.127	0.124	0.112	0.112	0.113	0.114	0.115	0.116	0.117	0.121	0.125	0.118
2022	0.130	0.130	0.126	0.115	0.114	0.115	0.117	0.118	0.118	0.120	0.123	0.128	0.121
2023	0.136	0.136	0.132	0.120	0.119	0.120	0.122	0.123	0.123	0.125	0.129	0.133	0.127
2024	0.142	0.142	0.138	0.125	0.124	0.125	0.127	0.128	0.129	0.130	0.134	0.139	0.132
2025	0.145	0.144	0.140	0.127	0.126	0.128	0.129	0.131	0.131	0.133	0.137	0.142	0.134
2026	0.147	0.147	0.143	0.129	0.129	0.130	0.132	0.133	0.133	0.135	0.139	0.144	0.137
2027	0.150	0.150	0.145	0.132	0.131	0.132	0.134	0.135	0.136	0.137	0.142	0.147	0.139
2028	0.153	0.152	0.148	0.134	0.133	0.135	0.136	0.138	0.138	0.140	0.144	0.149	0.142
2029	0.155	0.155	0.151	0.137	0.136	0.137	0.139	0.140	0.141	0.142	0.147	0.152	0.144

Northwest Burnertip Gas Price ($/MMBtu - Nominal$)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
2013	7.450	7.445	7.218	6.517	6.474	6.545	6.626	6.697	6.721	6.796	7.019	7.279	6.899
2014	7.162	7.157	6.940	6.259	6.223	6.291	6.373	6.436	6.463	6.541	6.754	7.008	6.634
2015	6.762	6.757	6.552	5.910	5.875	5.940	6.017	6.077	6.102	6.175	6.376	6.616	6.263
2016	6.685	6.681	6.477	5.843	5.809	5.872	5.948	6.008	6.033	6.105	6.304	6.541	6.192
2017	6.876	6.871	6.662	6.009	5.974	6.040	6.118	6.179	6.205	6.279	6.484	6.728	6.369
2018	7.244	7.240	7.019	6.331	6.295	6.363	6.446	6.510	6.538	6.616	6.831	7.088	6.710
2019	7.760	7.755	7.519	6.782	6.743	6.816	6.905	6.974	7.003	7.087	7.318	7.593	7.188
2020	7.645	7.641	7.408	6.682	6.643	6.716	6.803	6.871	6.900	6.982	7.210	7.481	7.082
2021	7.834	7.829	7.591	6.847	6.807	6.881	6.971	7.040	7.070	7.154	7.388	7.665	7.256
2022	8.023	8.018	7.774	7.012	6.971	7.047	7.139	7.210	7.240	7.327	7.565	7.850	7.431
2023	8.400	8.395	8.139	7.341	7.299	7.378	7.474	7.549	7.581	7.671	7.921	8.219	7.781
2024	8.777	8.772	8.505	7.671	7.626	7.710	7.810	7.888	7.921	8.016	8.277	8.588	8.130
2025	8.944	8.938	8.666	7.816	7.771	7.856	7.958	8.037	8.071	8.168	8.434	8.751	8.284
2026	9.114	9.108	8.831	7.965	7.919	8.005	8.109	8.190	8.225	8.323	8.594	8.917	8.442
2027	9.287	9.281	8.998	8.116	8.069	8.157	8.263	8.345	8.381	8.481	8.757	9.087	8.602
2028	9.463	9.457	9.169	8.270	8.222	8.312	8.420	8.504	8.540	8.642	8.923	9.259	8.765
2029	9.643	9.637	9.343	8.427	8.378	8.470	8.580	8.665	8.702	8.806	9.093	9.435	8.932

Portland General Electric Company
Avoided Cost Study
Sumas Gas Price Forecast

Table 14

Sumas Gas Price ($/MMBtu - Nominal$)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
2013	7.497	7.492	7.263	6.557	6.514	6.586	6.667	6.738	6.762	6.839	7.063	7.325	6.942
2014	7.207	7.202	6.983	6.298	6.261	6.330	6.412	6.476	6.503	6.581	6.796	7.051	6.675
2015	6.840	6.835	6.627	5.977	5.942	6.007	6.085	6.146	6.172	6.246	6.450	6.692	6.335
2016	6.764	6.760	6.554	5.911	5.877	5.941	6.018	6.078	6.104	6.177	6.378	6.618	6.265
2017	6.880	6.875	6.666	6.012	5.977	6.042	6.121	6.182	6.208	6.282	6.487	6.731	6.372
2018	7.207	7.202	6.983	6.298	6.261	6.330	6.412	6.476	6.503	6.581	6.796	7.051	6.675
2019	7.719	7.714	7.479	6.745	6.706	6.780	6.868	6.936	6.966	7.049	7.279	7.553	7.150
2020	7.783	7.778	7.542	6.802	6.762	6.836	6.925	6.994	7.024	7.107	7.339	7.616	7.209
2021	7.976	7.970	7.728	6.970	6.929	7.005	7.096	7.167	7.197	7.283	7.521	7.804	7.387
2022	8.168	8.163	7.914	7.137	7.096	7.174	7.267	7.339	7.370	7.458	7.702	7.992	7.565
2023	8.552	8.547	8.286	7.473	7.430	7.511	7.609	7.685	7.717	7.809	8.064	8.368	7.921
2024	8.936	8.931	8.659	7.809	7.764	7.849	7.951	8.030	8.064	8.160	8.427	8.744	8.277
2025	9.106	9.100	8.823	7.958	7.911	7.998	8.102	8.183	8.217	8.315	8.587	8.910	8.434
2026	9.279	9.273	8.991	8.109	8.062	8.150	8.256	8.338	8.373	8.473	8.750	9.079	8.595
2027	9.456	9.450	9.162	8.263	8.215	8.305	8.413	8.497	8.533	8.634	8.916	9.252	8.758
2028	9.635	9.629	9.336	8.420	8.371	8.463	8.573	8.658	8.695	8.798	9.086	9.428	8.924
2029	9.818	9.812	9.513	8.580	8.530	8.623	8.735	8.823	8.860	8.966	9.258	9.607	9.094

Variable Transportation Cost ($/MMBtu) $0.031900 Losses 1.73%

Transportation Cost ($/MMBtu - Nominal$)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
2013	0.162	0.162	0.158	0.145	0.145	0.146	0.147	0.148	0.149	0.150	0.154	0.159	0.152
2014	0.157	0.156	0.153	0.141	0.140	0.141	0.143	0.144	0.144	0.146	0.149	0.154	0.147
2015	0.150	0.150	0.147	0.135	0.135	0.136	0.137	0.138	0.139	0.140	0.143	0.148	0.141
2016	0.149	0.149	0.145	0.134	0.134	0.135	0.136	0.137	0.137	0.139	0.142	0.146	0.140
2017	0.151	0.151	0.147	0.136	0.135	0.136	0.138	0.139	0.139	0.141	0.144	0.148	0.142
2018	0.157	0.156	0.153	0.141	0.140	0.141	0.143	0.144	0.144	0.146	0.149	0.154	0.147
2019	0.165	0.165	0.161	0.149	0.148	0.149	0.151	0.152	0.152	0.154	0.158	0.163	0.156
2020	0.167	0.166	0.162	0.150	0.149	0.150	0.152	0.153	0.153	0.155	0.159	0.164	0.157
2021	0.170	0.170	0.166	0.152	0.152	0.153	0.155	0.156	0.156	0.158	0.162	0.167	0.160
2022	0.173	0.173	0.169	0.155	0.155	0.156	0.158	0.159	0.159	0.161	0.165	0.170	0.163
2023	0.180	0.180	0.175	0.161	0.160	0.162	0.164	0.165	0.165	0.167	0.171	0.177	0.169
2024	0.187	0.186	0.182	0.167	0.166	0.168	0.169	0.171	0.171	0.173	0.178	0.183	0.175
2025	0.189	0.189	0.185	0.170	0.169	0.170	0.172	0.173	0.174	0.176	0.180	0.186	0.178
2026	0.192	0.192	0.187	0.172	0.171	0.173	0.175	0.176	0.177	0.178	0.183	0.189	0.181
2027	0.195	0.195	0.190	0.175	0.174	0.176	0.177	0.179	0.180	0.181	0.186	0.192	0.183
2028	0.199	0.198	0.193	0.178	0.177	0.178	0.180	0.182	0.182	0.184	0.189	0.195	0.186
2029	0.202	0.202	0.196	0.180	0.179	0.181	0.183	0.185	0.185	0.187	0.192	0.198	0.189

Northwest Burnertip Gas Price ($/MMBtu - Nominal$)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
2013	7.659	7.654	7.421	6.703	6.659	6.732	6.814	6.887	6.911	6.989	7.217	7.484	7.094
2014	7.363	7.359	7.136	6.439	6.401	6.471	6.555	6.620	6.648	6.727	6.945	7.205	6.822
2015	6.990	6.986	6.774	6.112	6.077	6.143	6.223	6.284	6.311	6.386	6.593	6.840	6.476
2016	6.913	6.909	6.699	6.045	6.010	6.076	6.154	6.215	6.241	6.316	6.521	6.765	6.405
2017	7.031	7.026	6.813	6.148	6.112	6.179	6.259	6.321	6.347	6.423	6.631	6.880	6.514
2018	7.363	7.359	7.136	6.439	6.401	6.471	6.555	6.620	6.648	6.727	6.945	7.205	6.822
2019	7.885	7.880	7.641	6.894	6.854	6.929	7.018	7.088	7.118	7.203	7.437	7.715	7.305
2020	7.950	7.945	7.704	6.951	6.911	6.986	7.077	7.147	7.177	7.262	7.498	7.779	7.366
2021	8.145	8.140	7.893	7.122	7.081	7.158	7.251	7.323	7.353	7.441	7.683	7.971	7.547
2022	8.341	8.336	8.083	7.293	7.251	7.330	7.424	7.498	7.530	7.619	7.867	8.162	7.728
2023	8.732	8.726	8.462	7.635	7.590	7.673	7.772	7.850	7.883	7.976	8.236	8.544	8.090
2024	9.123	9.117	8.841	7.976	7.930	8.017	8.120	8.201	8.236	8.333	8.604	8.927	8.452
2025	9.296	9.290	9.008	8.127	8.080	8.168	8.274	8.356	8.391	8.491	8.767	9.096	8.612
2026	9.472	9.466	9.178	8.281	8.233	8.323	8.431	8.514	8.550	8.652	8.933	9.268	8.775
2027	9.651	9.645	9.352	8.438	8.389	8.480	8.590	8.675	8.712	8.816	9.102	9.444	8.941
2028	9.834	9.828	9.529	8.597	8.548	8.641	8.753	8.840	8.877	8.983	9.275	9.623	9.110
2029	10.020	10.014	9.710	8.760	8.709	8.804	8.918	9.007	9.045	9.153	9.450	9.805	9.283

Portland General Electric
Avoided Cost Study
Financial Parameters and Cost of Capital Data

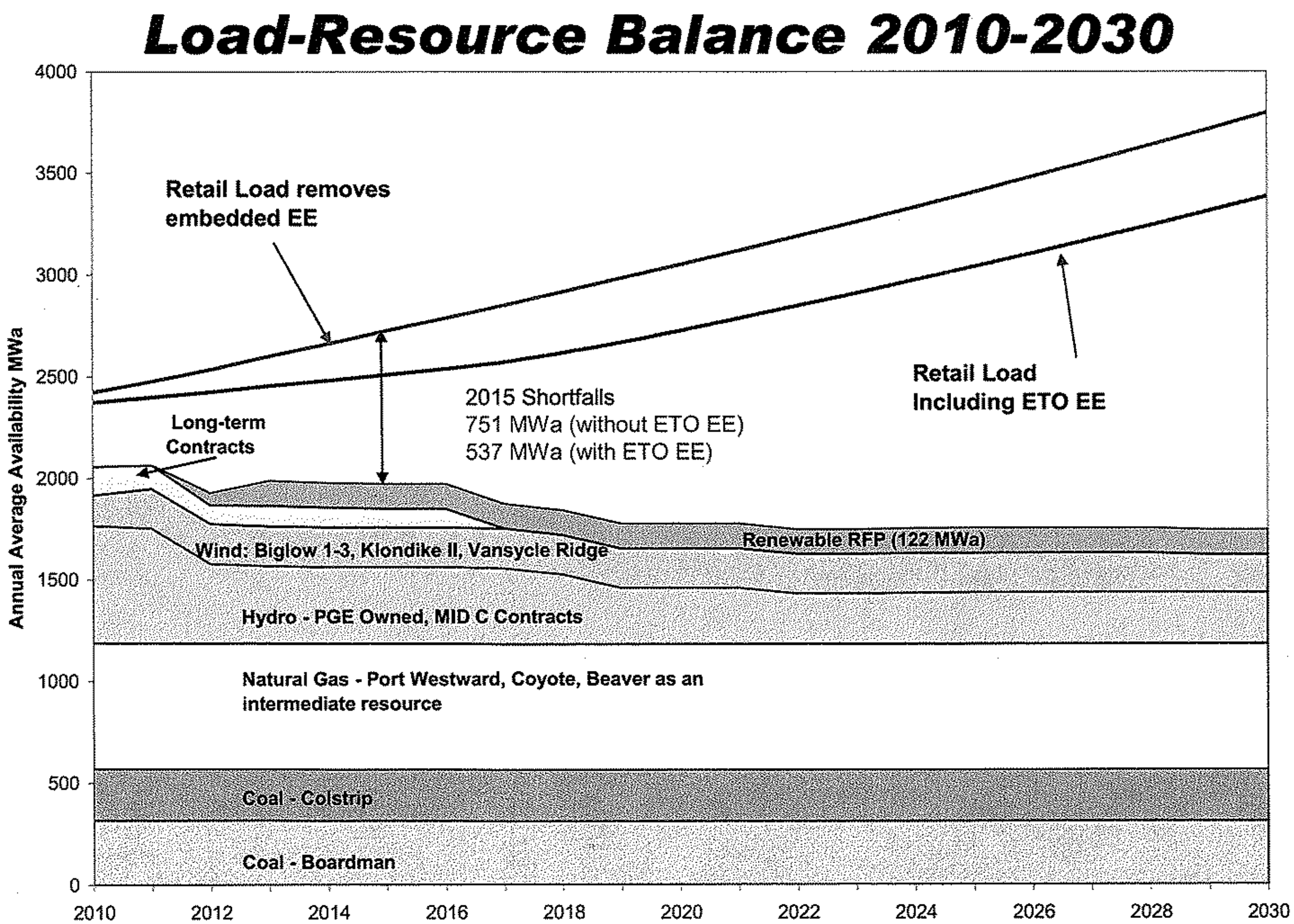
Table 15

FINANCIAL PARAMETERS			
Income Tax Rate			39.29%
Inflation Rate			1.90%
Capitalization:			
Preferred	0.00%	0.00%	0.00%
Common	50.00%	10.75%	5.38%
All Equity	50.00%		5.38%
Debt	50.00%	7.31%	3.66%
Cost of Capital			9.03%
After-Tax Nominal Cost of Capital			7.59%
After-Tax Real Cost of Capital			5.59%

SCCT Calculations			
Real LARR Factor	10.75%		
Installed Capital Cost 1-1-2011		1,194.16	$/kW
Annual Real Levelized Cost		135.88	$/kW-yr
Fixed O&M		3.00	$/kW-yr
SCCT Cost		138.88	$/kW-yr
SCCT Cost		11.57	$/kW-mo

CCCT Calculations			
Real LARR Factor	9.51%		
Installed Capital Cost 1-1-2011		1,547.73	$/kW
Annual Real Levelized Cost		149.99	$/kW-yr
Fixed O&M		14.13	$/kW-yr
CCCT Cost		164.13	$/kW-yr
CCCT Cost		13.68	$/kW-mo

PGE's Resource Need: Energy

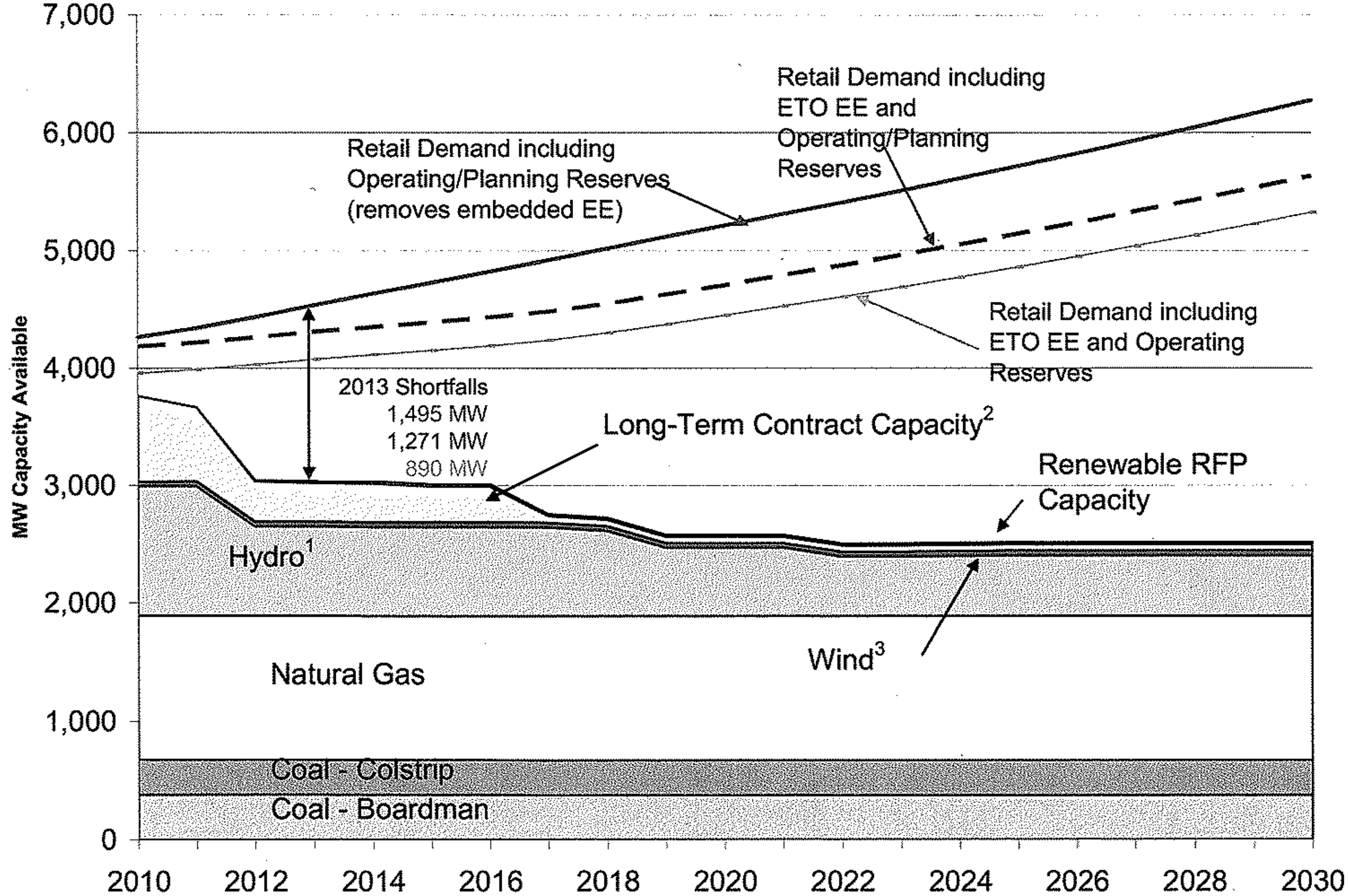


Retail load = Net System load – 5-yr opt out (about 30 MWa)
EE = Cumulative Energy Efficiency Forecast provided by ETO
Load growth assumed at 1.89% (on average from 2010 to 2030)

Portland General Electric

PGE's Resource Need: Capacity

Jan. Peak Load-Resource Balance 2010-2030



1) Includes PGE and Contracts
2) Includes 50 MW of DSG
3) 5% capacity value except for Klondike II

PGE
Portland General Electric

PGE Advice No. 09-16
Avoided Cost Model

Provided Electronically (CD) Only

Portland General Electric
Docket No. UM 1443
Proposed Revised Gas Price Forecast
For Schedule 201 - Table 5

TABLE 5												
Forecasted Gas Price - GPF ($/MMBTU) - Without Transportation												
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
2013	7.66	7.65	7.42	6.70	6.65	6.73	6.81	6.88	6.91	6.98	7.21	7.48
2014	8.18	8.17	7.92	7.15	7.11	7.18	7.28	7.35	7.38	7.47	7.71	8.00
2015	8.67	8.66	8.40	7.57	7.53	7.61	7.71	7.79	7.82	7.91	8.17	8.48
2016	8.97	8.96	8.69	7.83	7.79	7.87	7.98	8.06	8.09	8.19	8.45	8.77
2017	9.36	9.35	9.07	8.18	8.13	8.22	8.33	8.41	8.45	8.55	8.83	9.16
2018	9.66	9.66	9.36	8.44	8.39	8.49	8.60	8.68	8.72	8.82	9.11	9.45
2019	10.16	10.15	9.84	8.88	8.82	8.92	9.04	9.13	9.17	9.28	9.58	9.94
2020	10.76	10.75	10.42	9.40	9.35	9.45	9.57	9.67	9.71	9.82	10.14	10.52
2021	11.19	11.18	10.84	9.78	9.72	9.83	9.95	10.05	10.10	10.22	10.55	10.95
2022	11.63	11.63	11.27	10.17	10.11	10.22	10.35	10.45	10.50	10.62	10.97	11.38
2023	12.10	12.09	11.72	10.57	10.51	10.63	10.77	10.87	10.92	11.05	11.41	11.84
2024	12.58	12.58	12.19	11.00	10.93	11.05	11.20	11.31	11.36	11.49	11.87	12.31
2025	13.09	13.08	12.68	11.44	11.37	11.49	11.64	11.76	11.81	11.95	12.34	12.81
2026	13.34	13.33	12.92	11.65	11.59	11.71	11.87	11.98	12.03	12.18	12.58	13.05
2027	13.59	13.58	13.17	11.88	11.81	11.94	12.09	12.21	12.26	12.41	12.81	13.30
2028	13.85	13.84	13.42	12.10	12.03	12.16	12.32	12.44	12.50	12.64	13.06	13.55

Portland General Electric
Docket No. UM 1443
Proposed Revised PGE Schedule 201, Tables 1-7

TABLE 1
Avoided Costs
Fixed Price Option
On-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2009	N/A	N/A	N/A	N/A	N/A	N/A	N/A	32.71	31.59	32.46	41.21	50.34
2010	51.25	47.75	42.75	41.00	36.00	33.25	53.75	58.25	57.75	53.75	56.00	59.25
2011	60.30	56.80	53.55	47.55	40.80	39.55	64.05	66.80	63.55	58.80	62.05	65.05
2012	62.07	57.81	51.71	49.58	43.48	40.13	65.12	70.61	70.00	65.12	67.86	71.83
2013	99.14	99.11	97.48	92.45	92.14	92.65	93.23	93.74	93.91	94.45	96.05	97.92
2014	103.65	103.61	101.88	96.45	96.16	96.71	97.36	97.86	98.08	98.69	100.39	102.42
2015	107.93	107.89	106.05	100.30	100.00	100.57	101.26	101.80	102.03	102.68	104.48	106.63
2016	110.79	110.75	108.84	102.90	102.58	103.17	103.89	104.44	104.68	105.35	107.22	109.44
2017	114.71	114.67	112.68	106.47	106.14	106.76	107.51	108.09	108.34	109.04	110.98	113.30
2018	117.63	117.59	115.54	109.13	108.79	109.43	110.20	110.79	111.05	111.78	113.78	116.18
2019	122.04	121.99	119.84	113.10	112.74	113.42	114.22	114.85	115.12	115.89	118.00	120.51
2020	127.04	126.99	124.71	117.58	117.20	117.91	118.77	119.43	119.72	120.53	122.76	125.42
2021	131.18	131.13	128.76	121.34	120.94	121.68	122.58	123.27	123.56	124.41	126.73	129.50
2022	135.31	135.26	132.79	125.07	124.66	125.43	126.36	127.08	127.39	128.26	130.68	133.56
2023	139.71	139.66	137.09	129.06	128.64	129.44	130.40	131.15	131.47	132.38	134.90	137.89
2024	143.84	143.79	141.12	132.77	132.33	133.16	134.16	134.94	135.27	136.22	138.84	141.95
2025	148.58	148.52	145.75	137.07	136.60	137.47	138.51	139.32	139.67	140.65	143.37	146.61
2026	151.40	151.34	148.51	139.67	139.20	140.08	141.14	141.97	142.32	143.32	146.10	149.40
2027	154.28	154.22	151.33	142.32	141.84	142.74	143.82	144.66	145.02	146.05	148.87	152.23
2028	157.17	157.11	154.17	144.98	144.50	145.41	146.52	147.37	147.74	148.78	151.66	155.09

TABLE 2
Avoided Costs
Fixed Price Option
Off-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2009	N/A	N/A	N/A	N/A	N/A	N/A	N/A	26.59	27.21	27.71	35.21	43.71
2010	44.75	42.75	37.75	34.75	26.25	23.75	40.25	44.00	41.75	42.75	48.75	55.25
2011	55.30	51.80	48.05	36.80	29.80	27.30	45.30	50.55	50.30	49.80	53.80	57.05
2012	53.00	50.62	44.66	41.08	30.95	27.97	47.64	52.11	49.42	50.62	57.77	65.52
2013	66.37	66.33	64.70	59.67	59.37	59.88	60.46	60.97	61.14	61.68	63.28	65.15
2014	70.25	70.22	68.48	63.06	62.77	63.31	63.96	64.47	64.68	65.30	67.00	69.02
2015	73.90	73.86	72.02	66.27	65.97	66.54	67.23	67.77	68.00	68.65	70.45	72.60
2016	76.22	76.18	74.28	68.33	68.01	68.61	69.32	69.88	70.11	70.79	72.65	74.87
2017	79.26	79.22	77.23	71.02	70.69	71.31	72.06	72.64	72.89	73.59	75.54	77.85
2018	81.62	81.58	79.53	73.12	72.78	73.42	74.19	74.79	75.04	75.77	77.78	80.17
2019	85.35	85.30	83.15	76.41	76.05	76.72	77.53	78.16	78.43	79.19	81.31	83.82
2020	89.77	89.73	87.44	80.31	79.93	80.64	81.50	82.16	82.45	83.26	85.49	88.16
2021	93.08	93.03	90.66	83.24	82.84	83.59	84.48	85.17	85.47	86.31	88.63	91.40
2022	96.49	96.44	93.97	86.25	85.84	86.61	87.54	88.26	88.57	89.44	91.86	94.74
2023	100.02	99.97	97.40	89.38	88.95	89.75	90.71	91.46	91.78	92.69	95.21	98.20
2024	103.66	103.60	100.93	92.59	92.14	92.98	93.98	94.76	95.09	96.04	98.65	101.77
2025	107.50	107.45	104.67	95.99	95.53	96.39	97.44	98.25	98.59	99.58	102.30	105.54
2026	109.54	109.49	106.66	97.81	97.34	98.22	99.28	100.11	100.46	101.47	104.24	107.54
2027	111.62	111.56	108.68	99.67	99.19	100.09	101.17	102.01	102.37	103.39	106.22	109.58
2028	113.71	113.64	110.71	101.52	101.03	101.95	103.05	103.91	104.28	105.32	108.19	111.62

Portland General Electric
Docket No. UM 1443
Proposed Revised PGE Schedule 201, Tables 1-7

TABLE 3
Avoided Costs
On-Peak Resource Sufficiency Rate ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2009	N/A	N/A	N/A	N/A	N/A	N/A	N/A	32.71	31.59	32.46	41.21	50.34
2010	51.25	47.75	42.75	41.00	36.00	33.25	53.75	58.25	57.75	53.75	56.00	59.25
2011	60.30	56.80	53.55	47.55	40.80	39.55	64.05	66.80	63.55	58.80	62.05	65.05
2012	62.07	57.81	51.71	49.58	43.48	40.13	65.12	70.61	70.00	65.12	67.86	71.83

TABLE 4
Avoided Costs
Off-Peak Resource Sufficiency Rate ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2009	N/A	N/A	N/A	N/A	N/A	N/A	N/A	26.59	27.21	27.71	35.21	43.71
2010	44.75	42.75	37.75	34.75	26.25	23.75	40.25	44.00	41.75	42.75	48.75	55.25
2011	55.30	51.80	48.05	36.80	29.80	27.30	45.30	50.55	50.30	49.80	53.80	57.05
2012	53.00	50.62	44.66	41.08	30.95	27.97	47.64	52.11	49.42	50.62	57.77	65.52

TABLE 5
Forecasted Gas Price - GP_F ($/MMBTU) - Without Transportation

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2013	7.66	7.65	7.42	6.70	6.65	6.73	6.81	6.88	6.91	6.98	7.21	7.48
2014	8.18	8.17	7.92	7.15	7.11	7.18	7.28	7.35	7.38	7.47	7.71	8.00
2015	8.67	8.66	8.40	7.57	7.53	7.61	7.71	7.79	7.82	7.91	8.17	8.48
2016	8.97	8.96	8.69	7.83	7.79	7.87	7.98	8.06	8.09	8.19	8.45	8.77
2017	9.36	9.35	9.07	8.18	8.13	8.22	8.33	8.41	8.45	8.55	8.83	9.16
2018	9.66	9.66	9.36	8.44	8.39	8.49	8.60	8.68	8.72	8.82	9.11	9.45
2019	10.16	10.15	9.84	8.88	8.82	8.92	9.04	9.13	9.17	9.28	9.58	9.94
2020	10.76	10.75	10.42	9.40	9.35	9.45	9.57	9.67	9.71	9.82	10.14	10.52
2021	11.19	11.18	10.84	9.78	9.72	9.83	9.95	10.05	10.10	10.22	10.55	10.95
2022	11.63	11.63	11.27	10.17	10.11	10.22	10.35	10.45	10.50	10.62	10.97	11.38
2023	12.10	12.09	11.72	10.57	10.51	10.63	10.77	10.87	10.92	11.05	11.41	11.84
2024	12.58	12.58	12.19	11.00	10.93	11.05	11.20	11.31	11.36	11.49	11.87	12.31
2025	13.09	13.08	12.68	11.44	11.37	11.49	11.64	11.76	11.81	11.95	12.34	12.81
2026	13.34	13.33	12.92	11.65	11.59	11.71	11.87	11.98	12.03	12.18	12.58	13.05
2027	13.59	13.58	13.17	11.88	11.81	11.94	12.09	12.21	12.26	12.41	12.81	13.30
2028	13.85	13.84	13.42	12.10	12.03	12.16	12.32	12.44	12.50	12.64	13.06	13.55

TABLE 6
Variable O&M, Fixed Costs and Gas Transportation Forecast - VFG ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2013	13.99	13.99	13.95	13.84	13.84	13.85	13.86	13.87	13.88	13.89	13.92	13.96
2014	14.31	14.31	14.27	14.16	14.15	14.16	14.18	14.19	14.19	14.20	14.24	14.28
2015	14.63	14.63	14.59	14.47	14.46	14.47	14.49	14.50	14.51	14.52	14.56	14.61
2016	14.90	14.90	14.86	14.73	14.73	14.74	14.75	14.77	14.77	14.79	14.83	14.87
2017	15.25	15.25	15.21	15.07	15.06	15.08	15.09	15.11	15.11	15.13	15.17	15.22
2018	15.56	15.56	15.51	15.37	15.37	15.38	15.40	15.41	15.42	15.43	15.48	15.53
2019	15.90	15.90	15.85	15.71	15.70	15.71	15.73	15.75	15.75	15.77	15.81	15.87
2020	16.23	16.23	16.18	16.03	16.02	16.04	16.05	16.07	16.07	16.09	16.14	16.20
2021	16.61	16.61	16.56	16.39	16.39	16.40	16.42	16.44	16.44	16.46	16.51	16.57

Portland General Electric
Docket No. UM 1443
Proposed Revised PGE Schedule 201, Tables 1-7

2022	16.96	16.96	16.90	16.74	16.73	16.75	16.77	16.78	16.79	16.81	16.86	16.92
2023	17.32	17.32	17.26	17.09	17.08	17.10	17.12	17.13	17.14	17.16	17.21	17.28
2024	17.65	17.65	17.59	17.41	17.40	17.42	17.44	17.46	17.47	17.49	17.54	17.61
2025	18.06	18.06	18.00	17.81	17.80	17.82	17.84	17.86	17.87	17.89	17.95	18.02
2026	18.41	18.40	18.34	18.15	18.14	18.16	18.18	18.20	18.21	18.23	18.29	18.36
2027	18.76	18.75	18.69	18.50	18.49	18.50	18.53	18.55	18.55	18.58	18.64	18.71
2028	19.08	19.07	19.01	18.81	18.80	18.82	18.84	18.86	18.87	18.89	18.96	19.03

TABLE 7
Capacity Value - C ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2013	32.77	32.77	32.77	32.77	32.77	32.77	32.77	32.77	32.77	32.77	32.77	32.77
2014	33.40	33.40	33.40	33.40	33.40	33.40	33.40	33.40	33.40	33.40	33.40	33.40
2015	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03
2016	34.57	34.57	34.57	34.57	34.57	34.57	34.57	34.57	34.57	34.57	34.57	34.57
2017	35.45	35.45	35.45	35.45	35.45	35.45	35.45	35.45	35.45	35.45	35.45	35.45
2018	36.01	36.01	36.01	36.01	36.01	36.01	36.01	36.01	36.01	36.01	36.01	36.01
2019	36.69	36.69	36.69	36.69	36.69	36.69	36.69	36.69	36.69	36.69	36.69	36.69
2020	37.27	37.27	37.27	37.27	37.27	37.27	37.27	37.27	37.27	37.27	37.27	37.27
2021	38.10	38.10	38.10	38.10	38.10	38.10	38.10	38.10	38.10	38.10	38.10	38.10
2022	38.82	38.82	38.82	38.82	38.82	38.82	38.82	38.82	38.82	38.82	38.82	38.82
2023	39.69	39.69	39.69	39.69	39.69	39.69	39.69	39.69	39.69	39.69	39.69	39.69
2024	40.18	40.18	40.18	40.18	40.18	40.18	40.18	40.18	40.18	40.18	40.18	40.18
2025	41.08	41.08	41.08	41.08	41.08	41.08	41.08	41.08	41.08	41.08	41.08	41.08
2026	41.86	41.86	41.86	41.86	41.86	41.86	41.86	41.86	41.86	41.86	41.86	41.86
2027	42.65	42.65	42.65	42.65	42.65	42.65	42.65	42.65	42.65	42.65	42.65	42.65
2028	43.46	43.46	43.46	43.46	43.46	43.46	43.46	43.46	43.46	43.46	43.46	43.46