SCHEDULE 201
QUALIFYING FACILITY
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.

AVAILABLE

In all territory served by the Company.

APPLICABLE

Applicable to Sellers of generation from small power production or cogeneration facilities that are QFs as defined in 18 Code of Federal Regulations (CFR) Section 292, the energy is delivered to the Company's system and made available for Company purchase, and the Seller meets all requirements herein described including establishing credit, providing proof of insurance, executing an interconnection agreement, a transmission agreement and a Power Purchase Agreement, where applicable.

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 **(T)** 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 Seller with a QF nameplate capacity rating of 10 MW or less as defined herein may elect the option of a Standard Contract. **(T)**

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. Negotiations for power purchase pricing will be based on the filed Avoided Costs in effect at that time.

STANDARD CONTRACT (Nameplate capacity of 10 MW or less) **(T)**

A Seller choosing a Standard Contract will complete all informational and price option selection requirements in the 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.

GUIDELINES FOR LESS THAN 10 MW FACILITIES

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

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

If the Seller desires to proceed with the Standard Contract after reviewing the Company's draft agreement, the Seller may request in writing that the Company prepare a final draft Standard Contract. The Company shall respond to this request within 15 business days. In connection with such request, the Seller 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 shall 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 shall be returned to the Seller. Prices and other terms and conditions in the power purchase agreement shall not be final and binding until the Standard Contract has been executed by both parties.

SCHEDULE 201 (Continued)

NEGOTIATED CONTRACT (Nameplate capacity of greater than 10 MW) **(N)**

A negotiated power purchase agreement is required for a QF with a nameplate capacity greater than 10 MW. A Seller with a QF with a nameplate capacity that is greater than 10 MW shall provide all the preliminary information requested under GUIDELINES FOR FACILITIES GREATER THAN 10 MW. A Seller with a facility that is less than 10 MW has the option to enter into a negotiated contract and shall provide all the preliminary information requested under GUIDELINES FOR FACILITIES GREATER THAN 10 MW.

GUIDELINES FOR GREATER THAN 10 MW FACILITIES
The Company shall provide a form power purchase agreement upon request to the Company. The Company shall send the form agreement to the Seller within seven business days of the request.

The Seller may request indicative power purchase prices. To obtain an indicative pricing proposal for a proposed project, the Seller must provide in writing, general project information reasonably required for the development of indicative pricing, including, but not limited to:

- demonstration of ability to obtain QF status
- design capacity (MW), station service requirements, and net amount of power to be delivered to the Company's electric system.
- generation technology and other related technology applicable to the site
- quantity and timing of monthly power deliveries (including project ability to respond to dispatch orders from the Company)
- proposed site location and electrical interconnection point
- status of interconnection and transmission arrangements
- proposed on-line date and outstanding permitting requirements
- motive force or fuel plan consisting of fuel type(s) and source(s)
- proposed contract term and pricing provisions

The Company shall not be obligated to provide an indicative pricing proposal until all the information described above has been received in writing from the Seller. Within 30 business days following receipt of all required information, the Company shall provide the Seller with an indicative pricing proposal, which may include other indicative terms and conditions, tailored to the individual characteristics of the proposed project. Such proposal may be used by the Seller to make determinations regarding project planning, financing and feasibility. However, such prices are indicative and are not final and binding. Prices and other terms and conditions are only final and binding to the extent contained in a power purchase agreement executed by both parties. The Company shall provide with the indicative prices a description of the methodology used to develop the prices.

The Avoided Cost Prices and pricing options specified in this schedule provides a starting point for negotiated prices, and shall be modified to address specific factors mandated by federal and state law, including the following factors found under 18 § CFR 292.304(e); **(N)**

SCHEDULE 201 (Continued)

GUIDELINES FOR GREATER THAN 10 MW FACILITIES (Continued) **(N)**

(e) Factors affecting rates for purchases. In determining avoided costs, the following factors shall, to the extent practicable, be taken into account.

(1) The data provided pursuant to 18 CFR § 292.302(b), (c), or (d), including State review of any such data;

(2) The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:

(i) The ability of the Company to dispatch the qualifying facility;

(ii) The expected or demonstrated reliability of the qualifying facility;

(iii) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;

(iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the Company's facilities;

(v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;

(vi) The individual and aggregate value of energy and capacity from qualifying facilities on the Company's system; and

(vii) The smaller capacity increments and the shorter lead time available with additions of capacity from qualifying facilities; and

(3) The relationship of the availability of energy or capacity from the qualifying facility as derived in part (e) (2) of this section, to the ability of the Company to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and

(4) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the Company generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.

If the Seller desires to proceed with the project after reviewing the Company's indicative price proposal, the Seller must request in writing that the Company prepare a draft power purchase agreement to serve as the basis for negotiations between the parties. In connection with such request, the Seller must provide the Company with any additional project information that the Company reasonably determines to be necessary for the preparation of a draft power purchase agreement, which may include, but shall not be limited to:

- Updated information for the general project information categories listed above
- Evidence of adequate control of proposed site
- Timelines for obtaining any necessary governmental permits, approvals or authorizations
- Assurance of fuel supply or motive force
- Anticipated timelines for completion of key project milestones
- Evidence that any necessary interconnection studies have been completed and assurance that the necessary interconnection arrangements are under negotiation. **(N)**

SCHEDULE 201 (Continued)

GUIDELINES FOR GREATER THAN 10 MW FACILITIES (Continued) (N)

The Company shall not be obligated to provide the Seller with a draft power purchase agreement until all the relevant QF project information listed above has been received by the Company in writing. Within 30 business days following receipt of all required information, the Company shall provide the Seller with a draft power purchase agreement containing a comprehensive set of proposed terms and conditions, including a specific pricing proposal for power purchased from the project. The draft agreement shall serve as the basis for subsequent negotiations between the parties and unless clearly indicated, shall not be construed as a binding proposal by the Company.

After reviewing the draft power purchase agreement, the Seller may prepare an initial set of written comments and proposals regarding the agreement and forward them to the Company. The Company shall not be obligated to begin negotiations with a Seller until the Company has received an initial set of written comments. After the Company's receipt of comments and proposals, the Seller may contact the Company to schedule contract negotiations at such times and places as are mutually agreeable to the parties. In connection with such negotiations, the Company:

- Shall not unreasonably delay negotiations and shall respond in good faith to any additions, deletions or modifications to the draft power purchase agreement that are proposed by the Seller
- May request to visit the site of the proposed project if such a visit has not previously occurred
- Shall update its pricing proposals at appropriate intervals to accommodate any changes to the Company's avoided-cost calculations, the proposed project or proposed terms of the draft power purchase agreement
- May request any additional information from the Seller necessary to finalize the terms of the power purchase agreement and satisfy the Company's due diligence regarding the QF project.

When both parties are in full agreement as to all terms and conditions of the power purchase agreement, the Company shall prepare and forward to the Seller a final, executable version of the agreement. Prices and other terms and conditions in the power purchase agreement shall not be final and binding until the agreement has been executed by both parties.

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. A Standard Contract for Off System QFs is available upon request to the Company. (N)

SCHEDULE 201 (Continued)

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 2011, 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 2012 through 2026, 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.

(D)

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)

	Month												
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
2007	N/A	N/A	N/A	N/A	N/A	N/A	N/A	68.02	63.69	57.34	63.20	73.39	(C)
2008	74.92	72.37	66.26	59.12	54.28	51.48	77.47	87.91	81.80	68.80	75.43	82.56	
2009	83.33	77.72	69.57	60.14	55.56	51.74	79.50	91.73	83.07	69.57	76.45	83.58	
2010	83.33	77.72	69.57	60.14	55.56	51.74	79.50	91.73	83.07	69.57	76.45	83.58	
2011	80.72	75.30	67.40	58.28	53.85	50.15	77.02	88.86	80.47	67.49	74.15	81.05	
2012	76.80	76.82	75.39	67.85	67.19	67.70	68.24	68.56	68.81	69.38	71.68	73.98	
2013	78.57	78.60	77.13	69.42	68.75	69.26	69.82	70.15	70.40	70.99	73.34	75.69	
2014	81.76	81.79	80.25	72.15	71.44	71.99	72.57	72.91	73.18	73.80	76.27	78.74	
2015	86.19	86.22	84.57	75.90	75.13	75.72	76.35	76.71	76.99	77.66	80.30	82.95	
2016	86.60	86.64	84.99	76.34	75.58	76.16	76.79	77.15	77.44	78.10	80.74	83.38	
2017	88.83	88.86	87.17	78.32	77.54	78.13	78.78	79.15	79.44	80.11	82.82	85.52	
2018	90.87	90.91	89.18	80.11	79.31	79.92	80.58	80.96	81.26	81.95	84.72	87.49	
2019	94.39	94.42	92.61	83.11	82.28	82.92	83.61	84.00	84.32	85.04	87.94	90.84	
2020	97.83	97.87	95.97	86.05	85.17	85.84	86.56	86.98	87.30	88.06	91.09	94.12	
2021	100.17	100.21	98.27	88.11	87.22	87.90	88.64	89.07	89.40	90.18	93.28	96.38	
2022	102.47	102.51	100.52	90.14	89.23	89.92	90.68	91.11	91.45	92.25	95.42	98.59	
2023	104.89	104.93	102.90	92.28	91.34	92.06	92.83	93.27	93.62	94.43	97.68	100.92	
2024	107.13	107.17	105.10	94.23	93.27	94.00	94.79	95.25	95.60	96.43	99.75	103.07	
2025	109.69	109.73	107.61	96.49	95.52	96.26	97.07	97.54	97.90	98.75	102.15	105.54	
2026	112.21	112.26	110.08	98.71	97.71	98.47	99.30	99.78	100.15	101.02	104.49	107.97	(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	
2007	N/A	N/A	N/A	N/A	N/A	N/A	N/A	49.42	50.44	49.19	54.28	64.98	**(C)**
2008	67.02	62.95	56.07	43.84	36.71	34.67	58.61	72.37	69.82	61.16	66.77	74.41	
2009	77.98	64.47	56.83	45.37	37.22	36.20	60.14	73.90	69.31	61.16	66.77	74.41	
2010	75.54	62.48	55.08	43.98	36.08	35.11	58.28	71.60	67.15	59.27	64.69	72.09	
2011	74.54	61.65	54.36	43.41	35.63	34.66	57.51	70.65	66.28	58.58	63.93	71.23	
2012	60.40	60.43	58.99	51.46	50.80	51.30	51.85	52.17	52.41	52.99	55.29	57.59	
2013	61.80	61.83	60.36	52.65	51.98	52.49	53.05	53.38	53.63	54.22	56.57	58.92	
2014	64.61	64.64	63.09	55.00	54.29	54.83	55.42	55.76	56.02	56.64	59.11	61.58	
2015	68.64	68.67	67.02	58.34	57.58	58.17	58.79	59.16	59.44	60.11	62.75	65.40	
2016	68.71	68.74	67.09	58.44	57.69	58.27	58.89	59.26	59.54	60.20	62.84	65.48	
2017	70.40	70.44	68.75	59.89	59.11	59.71	60.35	60.72	61.01	61.69	64.39	67.10	
2018	72.08	72.12	70.39	61.32	60.52	61.13	61.79	62.17	62.47	63.16	65.93	68.70	
2019	75.16	75.20	73.39	63.89	63.06	63.69	64.38	64.78	65.09	65.82	68.72	71.62	
2020	78.23	78.26	76.37	66.44	65.57	66.24	66.96	67.38	67.70	68.46	71.49	74.52	
2021	80.05	80.09	78.15	68.00	67.11	67.79	68.52	68.95	69.28	70.06	73.16	76.26	
2022	81.89	81.93	79.95	69.56	68.65	69.34	70.10	70.53	70.87	71.67	74.84	78.01	
2023	83.77	83.81	81.78	71.15	70.22	70.94	71.71	72.15	72.50	73.31	76.56	79.80	
2024	85.66	85.70	83.63	72.76	71.80	72.53	73.32	73.78	74.14	74.97	78.29	81.60	
2025	87.66	87.70	85.58	74.46	73.48	74.23	75.04	75.50	75.87	76.72	80.11	83.51	
2026	89.67	89.72	87.55	76.17	75.17	75.93	76.76	77.24	77.61	78.48	81.95	85.43	**(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. All other purchases will be at On-Peak prices. (See Appendix 1, the Standard Contract for defined terms.)

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD CONTRACTS (Continued)

MARKET BASED PRICE OPTIONS: **(M)**

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 = 6,776 BTU/kWh
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. **(M)**

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 2008. The monthly On- and Off-Peak prices will be applied for all Market Based Price Options.

TABLE 3												
On-Peak Resource Sufficiency Rate ($/MWH)												
	Month											
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2007	N/A	N/A	N/A	N/A	N/A	N/A	N/A	68.02	63.69	57.34	63.20	73.39
2008	74.92	72.37	66.26	59.12	54.28	51.48	77.47	87.91	81.80	68.80	75.43	82.56
2009	83.33	77.72	69.57	60.14	55.56	51.74	79.50	91.73	83.07	69.57	76.45	83.58
2010	83.33	77.72	69.57	60.14	55.56	51.74	79.50	91.73	83.07	69.57	76.45	83.58
2011	80.72	75.30	67.40	58.28	53.85	50.15	77.02	88.86	80.47	67.49	74.15	81.05

(C)
(C)

TABLE 4												
Off-Peak Resource Sufficiency Rate ($/MWH)												
	Month											
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2007	N/A	N/A	N/A	N/A	N/A	N/A	N/A	49.42	50.44	49.19	54.28	64.98
2008	67.02	62.95	56.07	43.84	36.71	34.67	58.61	72.37	69.82	61.16	66.77	74.41
2009	77.98	64.47	56.83	45.37	37.22	36.20	60.14	73.90	69.31	61.16	66.77	74.41
2010	75.54	62.48	55.08	43.98	36.08	35.11	58.28	71.60	67.15	59.27	64.69	72.09
2011	74.54	61.65	54.36	43.41	35.63	34.66	57.51	70.65	66.28	58.58	63.93	71.23

(C)
(C)

SCHEDULE 201 (Continued)

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

2) Deadband Index Gas Price Option **(M)**

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 **(T)**
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 **(M)**

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; **(T)** (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 0.204 ¢ per kWh for wholesale wheeling. **(M)**

SCHEDULE 201 (Continued)

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

The tables below contain the gas pricing components for Option 1 (Fixed Price Option) and Option 2 (Deadband Index Gas Price Option).

TABLE 5
Forecasted Gas Price - GP_F($/MMBTU)

	Month												
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
2012	7.084	7.080	6.895	5.880	5.784	5.844	5.908	5.952	5.992	6.077	6.410	6.743	(C)
2013	7.245	7.241	7.052	6.013	5.915	5.976	6.042	6.087	6.128	6.214	6.555	6.896	
2014	7.610	7.606	7.408	6.316	6.213	6.278	6.347	6.394	6.437	6.528	6.886	7.244	
2015	8.151	8.146	7.934	6.765	6.654	6.723	6.797	6.848	6.894	6.991	7.375	7.758	
2016	8.125	8.120	7.908	6.743	6.633	6.702	6.776	6.826	6.872	6.969	7.351	7.733	
2017	8.325	8.320	8.103	6.909	6.796	6.867	6.942	6.994	7.041	7.141	7.532	7.924	
2018	8.525	8.520	8.298	7.075	6.959	7.032	7.109	7.162	7.211	7.312	7.713	8.114	
2019	8.925	8.920	8.688	7.407	7.286	7.362	7.443	7.499	7.549	7.655	8.075	8.495	
2020	9.326	9.320	9.077	7.740	7.613	7.692	7.777	7.835	7.888	7.999	8.437	8.876	
2021	9.540	9.534	9.286	7.917	7.787	7.868	7.955	8.014	8.069	8.182	8.631	9.080	
2022	9.759	9.753	9.499	8.099	7.966	8.049	8.137	8.198	8.254	8.370	8.829	9.288	
2023	9.983	9.977	9.717	8.285	8.149	8.234	8.324	8.386	8.443	8.562	9.032	9.502	
2024	10.212	10.206	9.940	8.475	8.336	8.423	8.515	8.579	8.637	8.758	9.239	9.720	
2025	10.446	10.440	10.168	8.669	8.527	8.616	8.711	8.776	8.835	8.959	9.451	9.943	
2026	10.686	10.680	10.401	8.868	8.723	8.814	8.911	8.977	9.038	9.165	9.668	10.171	(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 as identified in the Company's 2004 Integrated Resource Plan.

TABLE 6													
Variable O &M, Fixed Costs and Gas Transportation Forecast – VFG ($/MWH)													
						Month							
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
2012	12.07	12.07	12.05	11.90	11.88	11.89	11.90	11.91	11.91	11.93	11.98	12.02	(C)
2013	12.38	12.38	12.35	12.19	12.18	12.19	12.20	12.20	12.21	12.22	12.27	12.32	
2014	12.69	12.69	12.66	12.50	12.48	12.49	12.50	12.51	12.52	12.53	12.58	12.64	
2015	13.04	13.03	13.00	12.83	12.81	12.82	12.84	12.84	12.85	12.86	12.92	12.98	
2016	13.28	13.28	13.25	13.08	13.06	13.07	13.08	13.09	13.09	13.11	13.16	13.22	
2017	13.61	13.61	13.58	13.40	13.39	13.40	13.41	13.42	13.42	13.44	13.49	13.55	
2018	13.93	13.93	13.89	13.71	13.70	13.71	13.72	13.73	13.73	13.75	13.81	13.87	
2019	14.28	14.28	14.24	14.05	14.03	14.05	14.06	14.07	14.07	14.09	14.15	14.21	
2020	14.61	14.61	14.57	14.37	14.35	14.37	14.38	14.39	14.39	14.41	14.48	14.54	
2021	14.97	14.97	14.93	14.73	14.71	14.72	14.74	14.75	14.75	14.77	14.84	14.90	
2022	15.32	15.31	15.28	15.07	15.05	15.06	15.08	15.08	15.09	15.11	15.18	15.25	
2023	15.67	15.67	15.63	15.42	15.40	15.41	15.42	15.43	15.44	15.46	15.53	15.60	
2024	16.00	16.00	15.96	15.74	15.72	15.73	15.75	15.76	15.77	15.78	15.85	15.93	
2025	16.40	16.40	16.36	16.13	16.11	16.13	16.14	16.15	16.16	16.18	16.25	16.32	
2026	16.77	16.77	16.73	16.51	16.48	16.50	16.51	16.52	16.53	16.55	16.62	16.70	(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)													
Month													
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
2012	16.39	16.39	16.39	16.39	16.39	16.39	16.39	16.39	16.39	16.39	16.39	16.39	(C)
2013	16.77	16.77	16.77	16.77	16.77	16.77	16.77	16.77	16.77	16.77	16.77	16.77	
2014	17.16	17.16	17.16	17.16	17.16	17.16	17.16	17.16	17.16	17.16	17.16	17.16	
2015	17.55	17.55	17.55	17.55	17.55	17.55	17.55	17.55	17.55	17.55	17.55	17.55	
2016	17.90	17.90	17.90	17.90	17.90	17.90	17.90	17.90	17.90	17.90	17.90	17.90	
2017	18.43	18.43	18.43	18.43	18.43	18.43	18.43	18.43	18.43	18.43	18.43	18.43	
2018	18.79	18.79	18.79	18.79	18.79	18.79	18.79	18.79	18.79	18.79	18.79	18.79	
2019	19.22	19.22	19.22	19.22	19.22	19.22	19.22	19.22	19.22	19.22	19.22	19.22	
2020	19.60	19.60	19.60	19.60	19.60	19.60	19.60	19.60	19.60	19.60	19.60	19.60	
2021	20.12	20.12	20.12	20.12	20.12	20.12	20.12	20.12	20.12	20.12	20.12	20.12	
2022	20.58	20.58	20.58	20.58	20.58	20.58	20.58	20.58	20.58	20.58	20.58	20.58	
2023	21.12	21.12	21.12	21.12	21.12	21.12	21.12	21.12	21.12	21.12	21.12	21.12	
2024	21.47	21.47	21.47	21.47	21.47	21.47	21.47	21.47	21.47	21.47	21.47	21.47	
2025	22.03	22.03	22.03	22.03	22.03	22.03	22.03	22.03	22.03	22.03	22.03	22.03	
2026	22.54	22.54	22.54	22.54	22.54	22.54	22.54	22.54	22.54	22.54	22.54	22.54	(C)

Advice No. 07-17
Issued July 13, 2007
James J. Piro, Executive Vice President
Effective for service
on and after August 13, 2007

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 **(T)**
the transmission of power at its cost to the Company's service territory. **(T)**

INTERCONNECTION REQUIREMENTS

Except as otherwise provided in a generation Interconnection Agreement between the Company **(T)**
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 in Rule C or the Company's Interconnection Procedures contained in its FERC Open Access Transmission Tariff (OATT), as applicable. The Seller will bear full responsibility for the installation and safe operation of the interconnection facilities. **(M)**

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.

SCHEDULE 201 (Concluded)

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

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 shall be presented to the Commission for resolution.

SPECIAL CONDITIONS **(M)**

(D)

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

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. **(T)**

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. **(T)**

TERM OF AGREEMENT

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