SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES

AVAILABILITY

Service under this schedule is available for power delivered to the Company's control area within the State of Oregon.

APPLICABILITY

Service under this schedule is applicable to any Seller that:

1. Owns or operates a Qualifying Facility with a Nameplate Capacity rating of 10 MW or less and desires to sell Energy generated by the Qualifying Facility to the Company in compliance with all the terms and conditions of the Standard Contract;

2. Meets all applicable requirements of the Company's Generation Interconnection Process.

For Qualifying Facilities with a Nameplate Capacity rating greater than 10 MW, a negotiated Non-Standard Contract between the Seller and the Company is required.

DEFINITIONS

Energy means the electric energy, expressed in kWh, generated by the Qualifying Facility and delivered by the Seller to the Company in accordance with the conditions of this schedule and the Standard Contract. Energy is measured net of Losses and Station Use.

Generation Interconnection Process is the Company's generation interconnection application and engineering review process developed to ensure a safe and reliable generation interconnection in compliance with all applicable regulatory requirements, Prudent Electrical Practices and national safety standards. The Generation Interconnection Process is managed by the Company's Delivery Business Unit.

Heat Rate Conversion Factor is 7,100 MMBTU divided by 1,000.

Heavy Load (HL) Hours are the daily hours from hour ending 0700-2200 Mountain Time, (16 hours) excluding all hours on all Sundays, New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day. (N)

Intermittent describes a Qualifying Facility that produces electrical energy from the use of wind, solar or run of river hydro as the prime mover.

Light Load (LL) Hours are the daily hours from hour ending 2300-0600 Mountain Time (8 hours), plus all other hours on all Sundays, New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day. (N)

Losses are the loss of electric energy occurring as a result of the transformation and transmission of electric energy from the Qualifying Facility to the Point of Delivery.

Nameplate Capacity means the full-load electrical quantities assigned by the designer to a generator and its prime mover or other piece of electrical equipment, such as transformers and circuit breakers, under standardized conditions, expressed in amperes, kilovolt amperes, kilowatts, volts, or other appropriate units. Usually indicated on a nameplate attached to the individual machine or device.

(M)

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

DEFINITIONS (Continued)

Non-Standard Contract is a negotiated contract between any Seller that owns or operates a Qualifying Facility with a nameplate capacity rating greater than 10 MW and desires to sell Energy generated by the Qualifying Facility to the Company. The starting point for negotiation of price is the Avoided Cost Components established in this schedule and may be modified to address specific factors mandated by federal and state law, including (M)

1. The utility's system cost data; (M)

2. The availability of capacity or energy from a Qualifying Facility during the system daily and seasonal peak periods, including:

   a. The ability of the utility to dispatch the qualifying facility;

   b. The expected or demonstrated reliability of the qualifying facility;

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

   d. The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;

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

   f. The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and

   g. The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities; and

3. The relationship of the availability of energy or capacity from the Qualifying Facility to the ability of the electric utility 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 purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.

Non-Standard Contract is a negotiated contract between any Seller that owns or operates a Qualifying Facility with a Nameplate Capacity rating greater than 10 MW and desires to sell Energy generated by the Qualifying Facility to the Company. The guidelines for negotiating a Non-Standard Contract are more specifically described later in this schedule in Guidelines for Negotiation of Power Purchase Agreements for Qualifying Facilities with Nameplate Capacity of 10 MW or Larger.

Point of Delivery is the location where the Company's and the Seller's electrical facilities are inter-connected or where the Company's and the Seller's host transmission provider's electrical facilities are interconnected.

Prudent Electrical Practices are those practices, methods and equipment that are commonly used in prudent electrical engineering and operations to operate electric equipment lawfully and with safety, dependability, efficiency and economy.

PURPA means the Public Utility Regulatory Policies Act of 1978.

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

DEFINITIONS (Continued)

Qualifying Facility or QF is a cogeneration facility or a small power production facility which meets the PURPA criteria for qualification set forth in Subpart B of Part 292, Subchapter K, Chapter I, Title 18, of the Code of Federal Regulations.

Seasonality Factor is the factor used in determining the seasonal purchase price of energy. The applicable factors are:

73.50% for Season 1 (March, April, May);
120.00% for Season 2 (July, August, November, December);
100.00% for Season 3 (June, September, October, January, February).

Seller is any entity that owns or operates a Qualifying Facility and desires to sell Energy to the Company.

Standard Contracts are the pro forma Energy Sales Agreements the Company maintains on file with the Public Utility Commission of Oregon for Intermittent and non-intermittent on-system Qualifying Facilities and Intermittent and non-intermittent off-system Qualifying Facilities, with a Nameplate Capacity of 10 MW or less.

Station Use is electric energy used to operate the Qualifying Facility which is auxiliary to or directly related to the generation of electricity and which, but for the generation of electricity, would not be consumed by the Seller.

QUALIFYING FACILITY INFORMATION INQUIRY PROCESS

There are two separate processes required for a Seller to deliver and sell energy from a Qualifying Facility to the Company. These processes may be completed separately or simultaneously.

1. Generation Interconnection Process

All generation projects physically interconnecting to the Company's electrical system, regardless of size, location or ownership, must successfully complete the Generation Interconnection Process prior to the project delivering energy to the Company. A complete description of the Small Generator Interconnection Procedures, the Interconnection Application and Company contact information is maintained on the Idaho Power website at www.idahopower.com, or Seller may contact the Company's Delivery Business Unit at 1-208-388-2658 for further information.

All generation projects delivering power under the off-system Energy Sales Agreement must successfully complete a comparable Generation Interconnection Process with the Seller's host interconnection provider and transmission provider.

2. Energy Sales Agreement

To begin the process of completing a Standard Contract or negotiating a Non-Standard Contract, for a proposed project, the Seller must submit to the Company a request for an Energy Sales Agreement. All requests will be processed in the order of receipt by the Company.

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

QUALIFYING FACILITY INFORMATION INQUIRY PROCESS (Continued0

2. Energy Sales Agreement (Continued)

a. Communications

Unless otherwise directed by the Company, all communications to the Company regarding an Energy Sales Agreement should be directed in writing as follows:

Idaho Power Company
Cogeneration and Small Power Production
P O Box 70
Boise, Idaho 83707

b. Procedures

i. The Company's approved Energy Sales Agreement may be obtained from the Company's website at http://www.idahopower.com or if the Seller is unable to obtain it from the website, the Company will send a copy within 10 business days of a written request.

ii. In order to obtain a project specific draft Energy Sales Agreement the Seller must provide in writing to the Company, general project information required for the completion of an Energy Sales Agreement, including, but not limited to:

a) Date of request
b) Company / Organization that will be the contracting party
c) Contract notification information including name, address and telephone number
d) Verification that the Qualifying Facility meets the "Eligibility for Standard Rates and Contract" criteria
e) Copy of the Qualifying Facility's QF certificate
f) Copy of the FERC license (applicable to hydro projects only)
g) Location of the proposed project including general area and specific legal property description
h) Description of the proposed project including specific equipment models, types, sizes and configurations
i) Type of project (wind, hydro, geothermal etc)
j) Nameplate capacity of the proposed project
k) Schedule 85 pricing option selected
l) Desired term of the Energy Sales Agreement
m) Annual net energy amount
n) Maximum capacity of the Qualifying Facility
o) Estimated first energy date
p) Estimated operation date
q) Point of Delivery
r) Status of the Generation Interconnection Process

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

QUALIFYING FACILITY INFORMATION INQUIRY PROCESS (Continued)

b. Procedures (Continued)

iii. The Company shall provide a draft Energy Sales Agreement when all information described in Paragraph 2 above has been received in writing from the Seller. Within 15 business days following receipt of all information required in Paragraph 2 the Company will provide the Seller with a draft Energy Sales Agreement including current standard avoided cost prices and/or other optional pricing mechanisms as approved by the Oregon Public Utility Commission in this Schedule.

iv. The Company will respond within 15 business days to any written comments and proposals that the Seller provides in response to the draft Energy Sales Agreement.

v. If the Seller desires to proceed with the Energy Sales Agreement after reviewing the Company's draft Energy Sales Agreement, it may request in writing that the Company prepare a final draft Energy Sales Agreement. In connection with such request, the Seller must provide the Company with an updated status of the Generation Interconnection Process which indicates that the Seller’s provided information (i.e. first energy date, operation date, etc.) are realistically attainable and any additional or clarified project information that the Company reasonably determines to be necessary for the preparation of a final draft Energy Sales Agreement. Once the Company has received the written request for a final draft Energy Sales Agreement and all additional or clarified project information that the Company reasonably determines to be necessary for the preparation of a final draft Energy Sales Agreement, the Company will provide Seller with a final draft Energy Sales Agreement within 15 business days.

vi. After reviewing the final draft Energy Sales Agreement, the Seller may either prepare another set of written comments and proposals or approve the final draft Energy Sales Agreement. If the Seller prepares written comments and proposals, the Company will respond within 15 business days to those comments and proposals.

vii. When both parties are in full agreement as to all terms and conditions of the final draft Energy Sales Agreement, the Company will prepare and forward to the Seller within 15 business days a final executable version of the Energy Sales Agreement. Once the Seller executes the Energy Sales Agreement and returns all copies to the Company, the Company will execute the Energy Sales Agreement. Following the Company’s execution a completely executed copy will be returned to the Seller. Prices and other terms and conditions in the Energy Sales Agreement will not be final and binding until the Energy Sales Agreement has been executed by both parties.

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

AVOIDED COST PRICE (C)

Standard Avoided Cost Prices for Baseload QF

Year	Capacity Price $/kW-yr	Capacity Cost Allocated to On-Peak Hours ($/MWh)	Energy Only Price $/MWh	On-Peak $/MWh	Off-Peak $/MWh
	(a)	(b)	(c)	(d)	(e)
2015	Market Based Prices through 2015			$26.16	$20.94
2016	$66.20	$13.62	$36.45	$50.07	$36.45
2017	$68.19	$14.03	$40.23	$54.26	$40.23
2018	$70.24	$14.45	$40.43	$54.88	$40.43
2019	$72.34	$14.88	$43.66	$58.54	$43.66
2020	$74.51	$15.33	$48.47	$63.80	$48.47
2021	$76.75	$15.79	$51.14	$66.93	$51.14
2022	$79.05	$16.26	$53.49	$69.75	$53.49
2023	$81.42	$16.75	$56.26	$73.01	$56.26
2024	$83.86	$17.25	$57.44	$74.69	$57.44
2025	$86.37	$17.77	$60.86	$78.63	$60.86
2026	$88.96	$18.30	$64.06	$82.36	$64.06
2027	$91.63	$18.85	$65.01	$83.86	$65.01
2028	$94.38	$19.41	$64.38	$83.79	$64.38
2029	$97.22	$20.00	$64.65	$84.65	$64.65
2030	$100.13	$20.60	$66.12	$86.72	$66.12
2031	$103.14	$21.21	$68.44	$89.65	$68.44
2032	$106.23	$21.85	$71.91	$93.76	$71.91
2033	$109.41	$22.50	$74.97	$97.47	$74.97
2034	$112.70	$23.18	$77.61	$100.79	$77.61
2035	$116.08	$23.88	$81.08	$104.96	$81.08
2036	$119.56	$24.59	$84.83	$109.42	$84.83
2037	$123.15	$25.33	$87.40	$112.73	$87.40
2038	$126.84	$26.09	$90.69	$116.78	$90.69
2039	$130.64	$26.87	$94.66	$121.53	$94.66
2040	$134.56	$27.68	$99.84	$127.52	$99.84

(C)

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

AVOIDED COST PRICE (CONTINUED)

Standard Avoided Cost Prices for Wind QF (C)

Year	Capacity Price $/kW-yr	Capacity Cost Allocated to On-Peak Hours ($/MWh)	Energy Only Price $/MWh	Wind Capacity Contribution	Capacity Payment On-Peak Hours $/MWh	Wind Integration Charge $/MWh	On-Peak $/MWh	Off-Peak $/MWh
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
2015	Market Based Prices through 2015					$6.50	$19.66	$14.44
2016	$66.20	$13.62	$36.45	3.9%	$0.53	$6.50	$30.48	$29.95
2017	$68.19	$14.03	$40.23	3.9%	$0.55	$6.50	$34.28	$33.73
2018	$70.24	$14.45	$40.43	3.9%	$0.56	$6.50	$34.49	$33.93
2019	$72.34	$14.88	$43.66	3.9%	$0.58	$6.50	$37.74	$37.16
2020	$74.51	$15.33	$48.47	3.9%	$0.60	$6.50	$42.57	$41.97
2021	$76.75	$15.79	$51.14	3.9%	$0.62	$6.50	$45.26	$44.64
2022	$79.05	$16.26	$53.49	3.9%	$0.63	$6.50	$47.62	$46.99
2023	$81.42	$16.75	$56.26	3.9%	$0.65	$6.50	$50.41	$49.76
2024	$83.86	$17.25	$57.44	3.9%	$0.67	$6.50	$51.61	$50.94
2025	$86.37	$17.77	$60.86	3.9%	$0.69	$6.50	$55.05	$54.36
2026	$88.96	$18.30	$64.06	3.9%	$0.71	$6.50	$58.27	$57.56
2027	$91.63	$18.85	$65.01	3.9%	$0.74	$6.50	$59.25	$58.51
2028	$94.38	$19.41	$64.38	3.9%	$0.76	$6.50	$58.64	$57.88
2029	$97.22	$20.00	$64.65	3.9%	$0.78	$6.50	$58.93	$58.15
2030	$100.13	$20.60	$66.12	3.9%	$0.80	$6.50	$60.42	$59.62
2031	$103.14	$21.21	$68.44	3.9%	$0.83	$6.50	$62.77	$61.94
2032	$106.23	$21.85	$71.91	3.9%	$0.85	$6.50	$66.26	$65.41
2033	$109.41	$22.50	$74.97	3.9%	$0.88	$6.50	$69.35	$68.47
2034	$112.70	$23.18	$77.61	3.9%	$0.90	$6.50	$72.01	$71.11
2035	$116.08	$23.88	$81.08	3.9%	$0.93	$6.50	$75.51	$74.58
2036	$119.56	$24.59	$84.83	3.9%	$0.96	$6.50	$79.29	$78.33
2037	$123.15	$25.33	$87.40	3.9%	$0.99	$6.50	$81.89	$80.90
2038	$126.84	$26.09	$90.69	3.9%	$1.02	$6.50	$85.21	$84.19
2039	$130.64	$26.87	$94.66	3.9%	$1.05	$6.50	$89.21	$88.16
2040	$134.56	$27.68	$99.84	3.9%	$1.08	$6.50	$94.42	$93.34

(C)

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

AVOIDED COST PRICE (CONTINUED)

Standard Avoided Cost Prices for PV Solar QF (C)

Year	Capacity Price	Capacity Cost Allocated to On-Peak Hours	Energy Only Price	PV Solar Capacity Contribution	Capacity Payment On-Peak Hours	On-Peak	Off-Peak
	$/kW-yr	($/MWh)	$/MWh		$/MWh	$/MWh	$/MWh
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
2015	Market Based Prices through 2015					$26.16	$20.94
2016	$66.20	$13.62	$36.45	32.0%	$4.36	$40.81	$36.45
2017	$68.19	$14.03	$40.23	32.0%	$4.49	$44.72	$40.23
2018	$70.24	$14.45	$40.43	32.0%	$4.62	$45.05	$40.43
2019	$72.34	$14.88	$43.66	32.0%	$4.76	$48.42	$43.66
2020	$74.51	$15.33	$48.47	32.0%	$4.91	$53.38	$48.47
2021	$76.75	$15.79	$51.14	32.0%	$5.05	$56.19	$51.14
2022	$79.05	$16.26	$53.49	32.0%	$5.20	$58.69	$53.49
2023	$81.42	$16.75	$56.26	32.0%	$5.36	$61.62	$56.26
2024	$83.86	$17.25	$57.44	32.0%	$5.52	$62.96	$57.44
2025	$86.37	$17.77	$60.86	32.0%	$5.69	$66.55	$60.86
2026	$88.96	$18.30	$64.06	32.0%	$5.86	$69.92	$64.06
2027	$91.63	$18.85	$65.01	32.0%	$6.03	$71.04	$65.01
2028	$94.38	$19.41	$64.38	32.0%	$6.21	$70.59	$64.38
2029	$97.22	$20.00	$64.65	32.0%	$6.40	$71.05	$64.65
2030	$100.13	$20.60	$66.12	32.0%	$6.59	$72.71	$66.12
2031	$103.14	$21.21	$68.44	32.0%	$6.79	$75.23	$68.44
2032	$106.23	$21.85	$71.91	32.0%	$6.99	$78.90	$71.91
2033	$109.41	$22.50	$74.97	32.0%	$7.20	$82.17	$74.97
2034	$112.70	$23.18	$77.61	32.0%	$7.42	$85.03	$77.61
2035	$116.08	$23.88	$81.08	32.0%	$7.64	$88.72	$81.08
2036	$119.56	$24.59	$84.83	32.0%	$7.87	$92.70	$84.83
2037	$123.15	$25.33	$87.40	32.0%	$8.11	$95.51	$87.40
2038	$126.84	$26.09	$90.69	32.0%	$8.35	$99.04	$90.69
2039	$130.64	$26.87	$94.66	32.0%	$8.60	$103.26	$94.66
2040	$134.56	$27.68	$99.84	32.0%	$8.86	$108.70	$99.84

(C)

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

NET ENERGY PURCHASE PRICE

(D)(M)

For contract years one (1) through (15) fifteen, the monthly Net Energy Purchase Price will be calculated as follows: (N)

For all Energy delivered to the Company on a monthly basis during HL hours the Net Energy Purchase Price will be:

The On-Peak price from the preceding applicable Standard Avoided Cost Price tables multiplied by the appropriate Seasonality Factor.

For all Energy delivered to the Company on a monthly basis during LL hours the Net Energy Purchase Price will be:

The Off-Peak price from the preceding applicable Standard Avoided Cost Price tables multiplied by the appropriate Seasonality Factor. (N)

For all periods after the end of the fifteenth (15th) contract year, the Company will pay the Seller monthly, for Energy delivered and accepted at the Point of Delivery in accordance with the Seller's election of the following options: (C) (C)

(D)

Option 1 – Dead Band Method (T)

Net Energy Purchase Price =

On-Peak = (AGPU + Capacity Payment On-Peak Hours) X Seasonality Factor (C)
Off-Peak = AGPU X Seasonality Factor (T)

Actual Gas Price Used (AGPU) =
90% of Fuel Cost if
Indexed Fuel Cost is less than 90% Fuel Cost; else
110% of Fuel Cost if
Indexed Fuel Cost is greater than 110% Fuel Cost; else
Indexed Fuel Cost

where

On-Peak and Off-Peak are established in this schedule by QF resource type for the applicable calendar year of the actual Net Energy deliveries to the Company, and (C)

Indexed Fuel Cost is the applicable weighted monthly average index price of natural gas at Sumas multiplied by the Heat Rate Conversion Factor. (M)

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

NET ENERGY PURCHASE PRICE (Continued)

(M)

Option 2 – Gas Market Method (T)

Net Energy Purchase Price =

On-Peak = (AGPU + Capacity Payment On-Peak Hours) X Seasonality Factor (C)
Off-Peak = AGPU X Seasonality Factor (T)

Actual Gas Price Used (AGPU) = Indexed Fuel Cost

where

On-Peak and Off-Peak are established in this schedule by QF resource type for the applicable calendar year of the actual Net Energy deliveries to the Company, and (C)

Indexed Fuel Cost is the applicable weighted monthly average index price of natural gas at Sumas multiplied by the Heat Rate Conversion Factor.

MISCELLANEOUS PROVISIONS

Insurance

Qualifying Facilities with a Nameplate Capacity of 200 kilowatts or smaller are not required to provide evidence of liability insurance.

GUIDELINES FOR NEGOTIATION OF POWER PURCHASE AGREEMENTS
FOR QFS WITH A NAMEPLATE CAPACITY OF 10 MW OR LARGER

1. The Company will not impose terms and conditions beyond what is standard practice. The Edison Electric Institute master agreement and the Company's Standard Contracts are useful starting points in negotiating QF agreements.

2. The Company will provide an indicative pricing proposal for a QF that plans to provide firm energy or capacity and chooses avoided cost rates calculated at the time of the obligation. The Company will provide an indicative pricing proposal within 30 days of receipt of the information the Company requires from the QF. The proposal may include other terms and conditions, tailored to the individual characteristics of the proposed project. The avoided cost rates in the indicative pricing proposal will be based on the following:

   a. The starting point for negotiations is the avoided cost calculated under the modeling methodology approved by the Idaho Public Utilities Commission for QFs over 10 MW, as refined by the Oregon Public Utility Commission to incorporate stochastic analyses of electric and natural gas prices, loads, hydro and unplanned outages.

   b. The prospective QF may request in writing that the Company prepare a draft power purchase agreement to serve as the basis for negotiations. The Company may require additional information from the QF necessary to prepare a draft agreement.

(M)

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

GUIDELINES FOR NEGOTIATION OF POWER PURCHASE AGREEMENTS FOR QFS WITH A NAMEPLATE CAPACITY OF 10 MW OR LARGER (Continued) (M)

c. Within 30 days of receiving the required information, the Company will provide a draft power purchase agreement containing a comprehensive set of proposed terms and conditions.

d. The QF must submit in writing a statement of its intention to begin negotiations with the Company and may include written comments and proposals. The Company is not obligated to begin negotiations until it receives written notification from the QF. The Company will not unreasonably delay negotiations and will respond in good faith to all proposals by the QF.

e. When the parties have agreed, the Company will prepare a final version of the contract within 15 business days. A contract is not final and binding until signed by both parties.

f. At any time after 60 days from the date the QF has provided its written notification pursuant to paragraph d., the QF may file a complaint with the Oregon Public Utility Commission asking the Commission to adjudicate any unresolved contract terms and conditions.

3. QFs have the unilateral right to select a contract length of up to 20 years for a PURPA contract. The contract length selected by the QF may impact other contractual issues including, but not limited to, the avoided cost determination with respect to that QF.

4. The Company should consider the QF to be providing firm energy or capacity if the contract requires delivery of a specified amount of energy or capacity over a specified term and includes sanctions for non-compliance under a legally enforceable obligation. The Company shall not determine that a QF provides no capacity value simply because the Company did not select it through a competitive bidding process. For a QF providing firm energy or capacity:

a. The Company and the QF should negotiate the time periods when the QF may schedule outages and the advance notification requirement for such outages, using provisions in the Company's partial requirements tariffs as guidance.

b. The QF should be required to make best efforts to meet its capacity obligations during Company system emergencies.

c. The Company and the QF should negotiate security, default, damage and termination provisions that keep the Company and its ratepayers whole in the event the QF fails to meet obligations under the contract.

d. Delay of commercial operation should not be a cause of termination if the Company determines at the time of contract execution that it will be resource-sufficient as of the QF on-line date specified in the contract; however, damages may be appropriate.

e. Lack of natural motive force for testing to prove commercial operation should not be a cause of termination.

f. The Company should include a provision in the contract that states the Company may require a QF terminated due to its default and wishing to resume selling to the Company be subject to the terms of the original contract until its end date. (M)

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

GUIDELINES FOR NEGOTIATION OF POWER PURCHASE AGREEMENTS FOR QFS WITH A NAMEPLATE CAPACITY OF 10 MW OR LARGER (Continued) (M)

5. An "as available" obligation for delivery of energy, including deliveries in excess of Nameplate Capacity or the amount committed in the QF contract, should be treated as a non-firm commitment. Non-firm commitments should not be subject to minimum delivery requirements, default damages for construction delay or under-delivery, default damages for the QF choosing to terminate the contract early, or default security for these purposes.

6. For QFs unable to establish creditworthiness, the Company must at a minimum allow the QF to choose either a letter of credit or cash escrow for providing default security. When determining security requirements, the Company should take into account the risk associated with the QF based on such factors as its size and type of supply commitments.

7. When QF rates are based on avoided costs calculated at the time of delivery, the Company should use day-ahead on- and off-peak market index prices at the appropriate market hub(s).

   a. For QFs providing firm energy or capacity that choose this option, avoided cost rates should be based on day-ahead market index prices for firm purchases.

   b. For QFs providing energy on an "as available" basis, avoided cost rates should be based on day-ahead market index prices for non-firm purchases.

8. The Company should not make adjustments to standard avoided cost rates other than those approved by the Oregon Public Utility Commission and consistent with these guidelines.

9. The Company should make adjustments to avoided costs for reliability on an expected forward-looking basis. The Company should design QF rates to provide an incentive for the QF to achieve the contracted level and timing of energy deliveries.

10. The Company should make adjustments to avoided costs for dispatchability on a probabilistic, forward-looking basis.

11. If avoided cost rates for a QF are calculated at the time of the obligation and the Company's avoided resource is a fossil fuel plant, the Company should adjust avoided cost rates for the resource deficiency period to take into account avoided fossil fuel price risk.

12. Avoided cost rates for wind QFs should be adjusted for integration cost estimates based on studies conducted for the Company's system, unless the QF contracts for integration services with a third party.

   a. The Company should use the most recent integration cost data available, consistent with its evaluation of competitively bid and self-build wind resources.

   b. The portion of integration costs attributable to reserves costs should be based on the difference in such costs between the wind QF and the Company proxy plant.

(M)

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

GUIDELINES FOR NEGOTIATION OF POWER PURCHASE AGREEMENTS FOR QFS WITH A NAMEPLATE CAPACITY OF 10 MW OR LARGER (Continued) (M)

c. The Company should base first-year integration costs on the actual level of wind resources in the control area, plus the proposed QF. Integration costs for years two through five of the contract should be based on the expected level of wind resources in the control area each year, including the new resources the Company expects to add. Integration costs should be fixed at the year-five level, adjusted for inflation, for the remainder of the life of the wind projects in the control area.

d. The Company is prohibited from using a long-range planning target for wind resources as the basis for integration costs. However, if the Company is subject to near-term targets under a mandatory Renewable Portfolio Standard, the Company may base its integration costs on the level of renewable resources it must acquire over the next 10 years.

e. In determining integration costs, the Company should make reasonable estimates regarding the portion of renewable resources to be acquired that will be intermittent resources.

13. The Company should adjust avoided cost rates for QF line losses relative to the Company proxy plant based on a proximity-based approach.

14. The Company should evaluate whether there are potential savings due to transmission and distribution system upgrades that can be avoided or deferred as a result of the QFs location relative to the Company proxy plant and adjust avoided cost rates accordingly.

15. The Company should not adjust avoided cost rates for any distribution or transmission system upgrades needed to accept QF power. Such costs should be separately charged as part of the interconnection process.

16. The Company should not adjust avoided cost rates based on its determination of the additional cost it might incur for any debt imputation by a credit rating agency.

17. Regarding Surplus Sale and Simultaneous Purchase and Sale:

a. QFs may either contract with the Company for a “surplus sale” or for a “simultaneous purchase and sale” provided, however, that the QFs selection of either such contractual arrangement shall not be inconsistent with any retail tariff provision of the Company then in effect or any agreement between the QF and the Company;

b. The two sale/purchase arrangements described in paragraph 17. a will be available to QFs regardless of whether they qualify for standard contracts and rates or non-standard contracts and rates, however the “simultaneous purchase and sale” is not available to QFs not directly connected to the Company’s electrical system;

c. The negotiation parameters and guidelines should be the same for both sale/purchase arrangements described in paragraph 17. a; and

d. The avoided cost calculations by the Company do not require adjustment solely as a result of the selection of one of the sale/purchase arrangements described in paragraph 17.a., rather than the other. (M)