ATERWYNNE LLP
ATTORNEYS AT LAW

Suite 1800
222 S.W. Columbia
Portland, OR 97201-6618
503-226-1191
Fax 503-226-0079
www.aterwynne.com

February 27, 2006

VIA ELECTRONIC MAIL AND US MAIL

Filing Center
Oregon Public Utility Commission
550 Capitol Street NE #215
PO Box 2148
Salem, OR 97308-2148

Re: UM 1129 (Phase II, Track 2) – Direct Testimony of John R. Gale

Dear Sir or Madam:

Enclosed for filing in the above-named docket is the original and five copies of the Direct Testimony of John R. Gale on Behalf of Idaho Power Company. Please contact this office with any questions.

Very truly yours,

/s/ Jessica A. Gorham
Jessica A. Gorham

Enclosures

cc: UM 1129 Service List

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1129

PHASE II -- TRACK 2

In the Matter of PUBLIC UTILITY COMMISSION OF OREGON Staff's Investigation Relating to Electric Utility Purchases From Qualifying Facilities.

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

JOHN R. GALE

February 27, 2006

Q. Please state your name and business address for the record.

A. My name is John R. Gale and my business address is 1221 West Idaho Street, Boise, Idaho.

Q. By whom are you employed and in what capacity?

A. I am employed by Idaho Power Company ("Idaho Power" or the "Company") as the Vice President of Regulatory Affairs.

Q. Are you the same John R. Gale who has previously provided rebuttal testimony in Phase I and Phase II – Track 1 of this proceeding?

A. Yes, I am.

Q. What is the purpose of your direct testimony in this Track 2 of Phase II?

A. The principal focus of my testimony is to address issues associated with negotiating the purchase prices, terms and conditions to be included in non-standard contracts with large qualifying facilities ("QFs"). I will also address a number of the issues relating to both large and small QFs identified in Judge Kirkpatrick's November 17, 2005 Order establishing issues for resolution in this Track 2.

Q. When you refer to large QFs, what do you mean?

A. I am referring to QFs with a nameplate capacity larger than the 10 MW cap for entitlement to standard rates and standard contracts the Public Utility Commission of Oregon (the "Commission") set in Order No. 05-584.

Q. In its testimony in Phase I, Weyerhaeuser proposed that large QFs should have the option to require utilities to purchase their generation at prices that vary monthly based on an index of delivered natural gas prices. What is Idaho Power's response to this proposal?

A. Weyerhauser's proposal would require Idaho Power to depart from the energy acquisition framework laid out in its Integrated Resource Plan ("IRP") and would subject customers to an unacceptable level of price volatility risk. For these reasons, Idaho Power opposes Weyerhauser's proposal.

Q. Please explain.

A. In accordance with orders issued by both this Commission and the Idaho Public Utilities Commission, Idaho Power prepares a biennial IRP which is filed and acknowledged by both the Idaho and Oregon Commissions. Idaho Power believes that all resource acquisitions, including the acquisition of large QF resources, should be consistent with the risk and cost profiles of the portfolio resources identified in the acknowledged IRPs. Idaho Power does not currently have a base-load natural gas-fired generating resource in its resource portfolio. Idaho Power's most recent IRP, the 2004 IRP, does not include the construction or acquisition of a base-load generating resource fueled by natural gas. The decision *not* to include a base-load natural gas-fired generating resource in the IRP resource portfolio was based, in part, on the potential for increased customer cost due to the volatility of natural gas prices. Idaho Power believes that recent upward spikes in natural gas prices validates that decision. However, if the Company is required to enter into contracts with large QFs that include energy purchase prices that vary based on monthly spot market gas prices, the Company's integrated resource planning process will have been subverted and the Company and its customers will become subject to the very price volatility the Company sought to avoid in its long-term resource planning process.

Q. Has the Company performed any analysis of the potential costs associated with the purchase of energy from a large QF utilizing a contract in which the purchase price varies with monthly changes in the spot price for natural gas?

A. Yes. Recently a well-known developer of natural gas-fired power plants contacted the Company and advised the Company that it intended to pursue construction of a 111 MW natural gas-fired combined heat and power ("CHP") plant at an industrial facility located in Idaho Power's Oregon service area. The developer indicated it intended to require Idaho Power to purchase the energy generated by this large CHP for 20 years using purchase prices computed in a manner similar to the Option 3 (Gas Market) standard rate methodology that is available to small QFs. Based on that inquiry, the Company performed a number of analyses of the potential additional power supply expense associated with purchases from such a large generating facility.

Q. Can you summarize the results of those analyses?

A. The Company first looked at the CHP project from the standpoint of the additional revenue requirement associated with purchasing energy from the 111 MW facility at prices equivalent to the Option 1 standard rates (fixed rates) in Idaho Power's Oregon Schedule 85 beginning in 2008. This review did not reflect any adjustment for dispatchability, reliability, or other criteria to be considered in negotiating long-term non-standard contracts with large QFs. It assumed a take-and-pay contract at a 100% capacity factor. That analysis showed that the CHP project would trigger a cumulative revenue requirement over a 20-year contract term of approximately $1.128 billion.

The Company then looked at the cost of its total IRP resource portfolio, including the 111 MW CHP project and compared it to the cost of the Company's IRP resource portfolio without the CHP. Using Idaho Power's 2004 IRP resource stack and running the Company's dispatching and pricing model with Schedule 85 Option 1 (fixed rate) prices showed that the project would produce a total of approximately 1.9 million MWh of economic energy each year for 20 years. Economic energy is energy Idaho Power would need to meet its customers' loads at a price that is equal to or less than estimated market prices and less costly than other resources available to Idaho Power at the time. Using the Oregon Schedule 85 Option 1 pricing, the total cost to Idaho Power customers of this economic energy over the 20-year term of the contract would be approximately $140 million.

The Company then looked at the approximate quantity of excess energy the CHP would produce. Excess energy is energy generated at times when customer needs are low and/or the CHP generation would be more expensive than both the least-cost resource available or market prices. This analysis showed that the 111 MW project would produce 15.1 MWh of excess energy each year for 20 years. The cost of the 15.1 MWh of excess energy using

Oregon's Schedule 85 Option 1 prices is approximately $989 million over the term of the 20-year contract.

Of course, excess energy could be sold at the prevailing market prices. Again, using the Company's economic dispatch model, Idaho Power estimates the revenue from sales of this excess energy would be approximately $759 million. Based on this analysis, when compared to the cost of Idaho Power's current IRP resource portfolio, the extra cost to Idaho Power's customers of the CHP purchase is estimated to be approximately $230 million (excess energy cost less estimated market sales of excess energy) over the 20-year term of the CHP project's contract.

Q. Did the Company analyze the relative impact on customers if it were required to purchase the QF's output at a price varying with monthly changes in the spot market price for natural gas, as Weyerhauser argues it should be required to do?

A. Yes. In the case of the 111 MW QF, the developer indicates that it wishes to negotiate a contract including purchase prices that would vary based on a monthly index of delivered natural gas prices similar to the Option 3 (Gas Index) standard rate methodology in Idaho Power's Oregon Schedule 85, which is available to small QFs. Pricing the above-described purchase using the Option 3 (Gas Index) standard rate methodology for the period January 2005 through January 2006, using a 90% capacity factor for all hours in the day, indicated that using an Option 3-like pricing arrangement would have resulted in an additional annual revenue requirement in 2005 of approximately $8.3 million when compared to purchase prices based on Oregon Schedule 85 Option 1 (fixed-price) method. This represents a 14% increase in customer costs that would have been incurred during the 13-month January 2005 – January 2006 period. Exhibit 301 shows the computation of that comparison. Again, this analysis does not attempt to include any adjustment for dispatchability, reliability, or other factors that would be subject to negotiation in the development of a long-term, non-standard contract to purchase energy from a large QF.

Q. Did Idaho Power also analyze the purchase from the 111 MW project utilizing Option 2, the gas dead-band methodology and comparing it to Option 1 prices?

A. Yes. Pricing the same purchase using the Option 2 (gas dead-band method) standard rate methodology for the period January 2005 through January 2006 using a 90% capacity factor for all hours in the day shows that using an Option 2 pricing arrangement would have resulted in an additional annual revenue requirement in 2005 of approximately $1 million when compared to purchase prices based on Oregon's Schedule 85 Option 1 (fixed price) method. Exhibit 301 shows the computation of that comparison.

Q. Please summarize Idaho Power's position on pricing energy purchases from large QFs using monthly spot-market gas prices?

A. Idaho Power is opposed to using monthly natural gas price indices to set purchase prices for energy generated by large QFs. That includes using either Option 2 or Option 3 of the standard rates for small QFs as the starting point for negotiation. Idaho Power is willing to negotiate purchase prices for energy generated by large QFs based on Idaho Power's approved avoided costs. Idaho Power's approved avoided costs utilize the Northwest Power and Conservation Council's most recent long-term forecast for the price of natural gas as the fuel component. Idaho Power's approved avoided costs are not based on an index of monthly prices for natural gas. Requiring Idaho Power to purchase energy from a large QF using prices that vary monthly based on an index of delivered natural gas prices would transfer all of the risk of natural gas price volatility from the QF developer to Idaho Power's customers. Both the Oregon Commission and the Idaho Commission have acknowledged Idaho Power's resource plan as contained in its 2004 IRP. That plan does not include building or acquiring a base-load natural gas-fired generation resource, thereby providing some protection for Idaho Power's customers from price risk associated with volatile gas prices. That price risk should properly be assumed by the QF developer.

Q. Small QFs desiring to sell energy to Idaho Power can select Option 3 standard rates and receive purchase prices that vary monthly based on an index of delivered natural gas prices. Why is Idaho Power opposed to offering a similar pricing arrangement to large QFs?

A. There are several reasons. First, small combined heat and power projects that use natural gas as a fuel may not have the economic resources or economies of scale that would allow them to negotiate fixed-price contracts with gas suppliers or to hedge their purchases of natural gas. Because of their small size, they may have no choice but to be price takers.

Large CHP QFs, on the other hand, have a much greater ability to control their natural gas costs by the use of longer term contracts and more sophisticated physical and financial hedging techniques.

Finally, and probably most importantly, a large QF, whether it is actually fired by natural gas or not, can have a substantial effect on the Company's resource planning process and on its revenue requirement. Idaho Power's Oregon jurisdictional system peak load is approximately 110 MW. The 111 MW CHP project I discussed previously in my testimony would overwhelm the Company's total load in the state of Oregon.

Simply put, while Idaho Power questions whether standard rate Option 3 is representative of costs Idaho Power can actually avoid by purchasing from small QFs, Idaho Power can probably tolerate the increased revenue requirement associated with a small QF utilizing the Option 3 standard rate. But it is a totally different story when the Company and its customers are asked to absorb the increased costs and volatility associated with large QFs being paid purchase prices based on fluctuating monthly spot-market gas prices.

Q. Several of the issues on the adopted issue list, including issues 1(b) and 1(c), relate to the "firmness" of QF power supply commitments. Please describe the difference between firm and non-firm energy purchases.

A. Because a number of QFs over the years have desired to sell energy to Idaho Power on a non-firm basis, Idaho Power has an approved rate schedule in the state of Idaho, Schedule 86, which governs purchases and sales of non-firm energy from QFs. Non-firm energy is defined in Schedule 86 as energy sold by the QF to the Company on a "non-firm, if, as and when available basis." (Idaho Power Company, IPUC No. 26, Tariff No. 101, 3rd Revised Sheet No. 86-1.) A QF seller of non-firm energy can increase or curtail its energy deliveries to Idaho Power at any time without prior notice and without any economic consequence. A copy of Idaho Power's Rate Schedule 86 is enclosed with my testimony as Exhibit 302.

Q. Is Idaho Power recommending that the Oregon Commission allow Idaho Power to file a similar tariff in Oregon?

A. Yes. In Idaho, several QF projects have opted for the Schedule 86 non-firm agreement to better match their planned operations. These QF projects recognized that, due to the uncertainty of their resource or operating plans, they were unable to commit to any level of energy output to the utility. In some circumstances, this was the case in the early start-up phase of a project; once they gained experience with their operations, they opted to terminate the non-firm agreement (with no penalty) and transition into a firm QF agreement in accordance with the applicable rules and regulations at that time. In addition, having an approved tariff such as Idaho's Schedule 86 draws a clear distinction between firm and non-firm energy purchased from QFs.

Q. Please describe what you mean by firm energy purchases.

A. Idaho Power purchases hundreds of thousands of MWh of firm energy each year. Sellers under these firm energy purchases contractually commit to deliver energy at the times and in the amounts specified in the contract. In these non-QF firm energy contracts, failure to provide the specified amount of energy at the agreed-upon time results in the payment of damages, either actual damages or liquidated damages. Firm energy purchases for larger amounts of energy also require a more rigorous analysis of the creditworthiness of the Seller to provide assurance that the Seller has the financial strength to perform its obligations.

Q. Aren't most of the 87 contracts Idaho Power has signed with both Oregon and Idaho QFs "firm" energy contracts?

A. The contracts Idaho Power signed with QF developers prior to 2003 describe the energy deliveries as "firm." In actual practice, the amount of energy delivered under these earlier contracts can fluctuate from 0 MW to 10 MW, hour to hour, day to day, or month to month, completely at the discretion of the QF. As a result, Idaho Power only has a general idea of how much energy it can expect to receive from any QF at any time. As a result, the actual firmness of the energy deliveries under these pre-2003 contracts more closely resembles non-firm energy deliveries than firm energy deliveries.

Q. Is the same true for standard contracts in Oregon?

A. The answer to that question depends to some extent on the outcome of the Phase I proceedings in that case. Idaho Power is requesting that the QFs be required to provide monthly commitments as to the amount of energy they will deliver. Staff and ODOE are recommending that the commitment only be annual. If the commitment is annual, then it is difficult to characterize the Oregon standard QF contracts as providing firm energy.

Q. How does Idaho Power recommend that non-standard contracts with large QFs be structured to address firmness?

A. Idaho Power recommends that the Commission not restrict Idaho Power's ability to negotiate reasonable terms and conditions that require large QFs to make firm commitments as to the amounts of energy they will deliver and when they will deliver it. The contracts should include standard industry liquidated damage provisions for a failure to perform in accordance with the agreement and reasonable credit provisions to ensure that the large QF can actually pay damages to customers if the large QF fails to perform. Purchase prices should be negotiated to reflect the attributes, including reliability and dispatchability, as described in 18 CFR § 292.304, for the specific large QF resource just like other wholesale purchases the Company makes from other wholesale market participants. This is critical because, as demonstrated by the potential purchase from the 111 MW CHP I discussed earlier in my testimony, even a single large QF can have a material impact on Idaho Power's resource planning and customer rates.

Q. What about large intermittent QF resources, such as wind farms?

A. Idaho Power acknowledges that the intermittent nature of wind or solar resources will require that contracts for those resources include some additional flexibility in determining the "firmness" of the commitment to qualify for a firm energy purchase price. Idaho Power is currently undertaking a comprehensive study of the costs that the Company will incur to integrate increasingly greater levels of wind resources into its resource portfolio. That study is expected to be completed by the end of June. The wind integration study will give the Company much needed data to accurately assess the dispatchability and reliability of wind resources and assist in the negotiation of reasonable rates, terms and conditions for inclusion in contracts with large wind QF resources.

Q. Should purchase prices for energy purchased from large QF resources be based on the market prices obtained in competitive bidding programs undertaken by Idaho Power?

A. There is no question that competitive bidding programs yield the best indication of the costs Idaho Power can avoid by acquiring energy from a particular generation technology.

Q. Has Idaho Power obtained recent experience with competitive bid pricing for renewable resources?

Q. Yes. In 2005 Idaho Power issued a request for proposals ("RFP") for the acquisition of up to 200 MW of wind resources. Idaho Power expects to announce the results of that RFP in the very near future. Idaho Power also plans to issue an RFP for up to 100 MW of geothermal generating resources in the next month. As a result of the RFPs, Idaho Power will have current information on what costs it can avoid by purchasing wind resources and geothermal resources at market prices as compared to the cost of acquiring wind and geothermal resources from QFs at administratively determined prices. I can see no reason why customers should be expected to pay purchase prices for energy from large QFs that exceed the cost the utility would incur if it purchased the same resources with identical attributes by means of a competitive bid. In developing contracts for purchase from large QFs, the Company should be able to use the results of that bidding process in the negotiation process.

Q. Does the Company have any preliminary results from its wind resources RFP?

A. All indications suggest that purchasing wind resources via the RFP will be less expensive than purchasing wind resources from QFs utilizing administratively determined avoided-cost rates.

Unfortunately, if the Company continues to purchase additional amounts of wind resource from small QFs at higher, administratively determined avoided cost prices, it probably will be forced to cut back on the amount of wind resources purchased by competitive bid. Based on the Company's recent experience, that means that customers will probably pay more for wind resources than they otherwise would need to pay.

Q. One of the issues identified for resolution in this Phase 2 is the need for liability insurance for QFs with a design capacity at or under 200 kW. Does Idaho Power's experience with QFs in Idaho provide any guidance on this issue?

A. I believe it does. First, it should be stated that the size of a QF facility has nothing to do with the exposure that a utility has in the case of an electrical contact or other incident in which liability insurance would come into play. The need for liability insurance is just as serious for a 200 kW facility as it is for a 20 MW facility. That being said, Idaho Power currently has contracts with 11 QFs whose design capacity is 200 kW or less. Each one of those QFs maintains $1,000,000 of liability insurance. There is no indication that these small QFs are having any difficulty obtaining and paying for liability insurance. It is important to remember that a 200 kW facility operating at an 85% capacity factor using Oregon Schedule 85, Option 1 pricing would have been paid approximately $100,000 during calendar year 2005. Idaho Power's experience in Idaho demonstrates that requiring reasonable levels of liability insurance is not a barrier to the development and ongoing operation of very small QF projects.

Q. One of the issues to be determined in this proceeding is the impact on utility costs from imputed debt arising from QF contracts. What is imputed debt?

A. Like other electric utilities, when Idaho Power adds to its rate base, it must use some portion of shareholder equity to fund the investment. The Company must maintain its equity component above a certain level as it continues this investment process. If it does not, the debt level increases and the Company will face the threat of a bond-rating downgrade. Conversely, when the Company enters into a QF contract for purchased power, an obligation not reflected in its financial statements, an increase in equity is needed to maintain credit quality. Unless an equity component is provided to offset the debt-like obligation of long-term QF purchase power contracts, the Company faces off-balance sheet financial risk. For financial commitments that do not appear on the balance sheet, credit rating analysts impute the debt and interest equivalents on the financial statements of the Company to achieve a more accurate picture of the risk associated with their investment. The added equity needed to offset this imputed debt and interest represents the effect that long-term purchased power commitments have on the cost of capital. Any increase in the long-term obligation of a utility related to its capacity and energy resources will have to be backed by an appropriate amount of equity in the eyes of the investment community.

In reviewing its evaluation of the credit implications of QF related expenditures, S&P recently affirmed its position that such agreements are “debt-like in nature” and that the increased financial risk must be considered in evaluating a utility’s credit risks. As the rating agency explained in its publication, Utilities & Perspectives, May 12, 2003:

“[P]urchased power agreements typically result in the assumption of fixed costs representing the portion of the purchase price that is linked to the capacity component of the total payment. These fixed capacity payments are similar to debt service payments incurred by a utility that constructs debt-like financed power generation facilities. Therefore, whether a utility builds its own generation plants, or enters into a long-term power purchase agreement with a fixed-cost component, that utility is taking on financial risk."

Q. How does Idaho Power suggest that the Commission address imputed debt arising out of an increasing level of QF contract activity?

A. There is really nothing the Commission can do to prevent the additional cost associated with added equity required by increasing levels of imputed debt due to QF purchases. The only real issue is who will bear that additional cost? Unless avoided costs are adjusted to reflect the additional cost-of-capital expense associated with imputed debt, those higher costs will be passed on to the entire body of Idaho Power's customers. It seems equitable to Idaho Power that QF developers at least share some of the additional cost created by imputed debt by means of a reduction in the utility's avoided cost purchase prices.

Q. Does that complete your direct testimony?

A. Yes, it does.

PUBLIC UTILITY COMMISSION
OF
OREGON

CASE: UM 1129
WITNESS: John R. Gale

IDAHO POWER EXHIBIT 301

February, 2006

Idaho Power Company

Estimated Oregon Schedule 85 Energy Payments

Nameplate of proposed Project	111.00 MW
Capacity Factor	90.00%

	Energy			Option 1 -Fixed Prices			Option 2 - Gas Deadband			Option 3 - Gas Index		
Total	**533,866**	**417,982**	**951,847**	**$36,090,273**	**$18,287,929**	**$54,378,202**	**$36,533,747**	**$18,646,835**	**$55,180,581**	**$40,307,039**	**$21,687,552**	**$61,994,591**
						$57.13			**$57.97**			**$65.13**
	On-Peak	Off-Peak	Total	On-Peak	Off-Peak	Total	On-Peak	Off-Peak	Total	On-Peak	Off-Peak	Total
Jan-05	41,558	32,767	74,326	$2,810,595	$1,430,944	$4,241,538	$2,748,423	$1,381,924	$4,130,347	$2,748,423	$1,381,924	$4,130,347
Feb-05	39,960	29,570	69,530	$2,702,495	$1,291,339	$3,993,834	$2,546,251	$1,175,719	$3,721,970	$2,546,251	$1,175,719	$3,721,970
Mar-05	41,558	32,767	74,326	$2,065,787	$1,051,744	$3,117,531	$1,932,304	$946,497	$2,878,800	$1,924,667	$940,476	$2,865,143
Apr-05	41,558	30,370	71,928	$2,065,787	$974,787	$3,040,574	$2,122,021	$1,015,881	$3,137,902	$2,122,021	$1,015,881	$3,137,902
May-05	41,558	32,767	74,326	$2,065,787	$1,051,744	$3,117,531	$2,109,009	$1,085,822	$3,194,831	$2,109,009	$1,085,822	$3,194,831
Jun-05	39,960	31,968	71,928	$2,702,495	$1,396,043	$4,098,537	$2,527,870	$1,256,342	$3,784,212	$2,523,554	$1,252,890	$3,776,444
Jul-05	41,558	32,767	74,326	$3,372,714	$1,717,132	$5,089,846	$3,337,056	$1,689,018	$5,026,074	$3,337,056	$1,689,018	$5,026,074
Aug-05	41,558	32,767	74,326	$3,372,714	$1,717,132	$5,089,846	$3,315,812	$1,672,267	$4,988,079	$3,315,812	$1,672,267	$4,988,079
Sep-05	39,960	31,968	71,928	$2,702,495	$1,396,043	$4,098,537	$2,877,120	$1,535,743	$4,412,863	$3,204,472	$1,797,625	$5,002,097
Oct-05	43,157	31,169	74,326	$2,918,694	$1,361,141	$4,279,836	$3,107,290	$1,497,349	$4,604,639	$4,027,695	$2,162,086	$6,189,781
Nov-05	38,362	33,566	71,928	$3,113,274	$1,759,014	$4,872,288	$3,314,442	$1,935,036	$5,249,478	$4,734,174	$3,177,301	$7,911,476
Dec-05	41,558	32,767	74,326	$3,372,714	$1,717,132	$5,089,846	$3,590,646	$1,888,964	$5,479,609	$4,594,032	$2,680,095	$7,274,127
Jan-06	41,558	32,767	74,326	$2,824,724	$1,423,735	$4,248,459	$3,005,503	$1,566,272	$4,571,776	$3,119,872	$1,656,447	$4,776,320
Feb-06												
Mar-06												
Apr-06												
May-06												
Jun-06												
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Nov-06												
Dec-06												

PUBLIC UTILITY COMMISSION
OF
OREGON

CASE: UM 1129
WITNESS: John R. Gale

IDAHO POWER EXHIBIT 302

February, 2006

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PUC
Utility Program

SCHEDULE 85
COGENERATION AND SMALL POWER PRODUCTION STANDARD CONTRACT RATES

AVAILABILITY

Service under this schedule is available throughout the Company's service territory 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.

Heat Rate Conversion Factor is 7,100 MMBTU divided by 1000.

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.

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

RECEIVED
JUL 12 2005
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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

1) The utility's system cost data;

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.

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

DEFINITIONS (Continued)

Point of Delivery is the location where the Company's and the Seller's electrical facilities are inter-connected.

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.

Qualifying Facility 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 Contract is the Company's Energy Sales Agreement (10 MW or less) filed with the Public Utility Commission of Oregon.

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.

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

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, application and Company contact information is maintained on the Idaho Power website at www.idahopower.com, or Seller may contact the Company's Customer Service Center at 1-800-488-6151 for further information.

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 in written form to the Company a request for an Energy Sales Agreement. This request, at the minimum, should contain:

a. Date of request
b. Description of the proposed project
c. Type of project (wind, hydro, geothermal etc)
d. Nameplate capacity of the proposed project
e. Estimated monthly generation (kWh)
f. Estimated on-line date of the proposed project
g. Location of the proposed project
h. Company / Organization that will be the contracting party
i. Contact information including name, address and telephone number

All requests will be processed in the order of receipt by the Company. The request should be submitted to:

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

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

AVOIDED COST COMPONENTS

The Avoided Cost Components are calculated based upon the Surrogate Avoided Resource methodology (SAR) for determining the Company's standard avoided costs.

Year	Capacity Cost (mills/kWh)	Fuel Cost (mills/kWh)
2005	23.96	43.67
2006	24.52	43.45
2007	25.08	42.67
2008	25.66	41.46
2009	26.25	40.33
2010	26.86	39.19
2011	27.50	39.90
2012	28.13	40.54
2013	28.77	41.25
2014	29.44	41.96
2015	30.13	42.67
2016	30.83	44.02
2017	31.55	45.44
2018	32.27	47.00
2019	33.03	48.49
2020	33.78	50.06
2021	34.58	51.69
2022	35.39	53.32
2023	36.20	55.17
2024	37.05	56.94
2025	37.91	58.72
2026	38.79	60.63
2027	39.69	62.62
2028	40.61	64.61
2029	41.57	66.74
2030	42.54	68.87

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

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NET ENERGY PURCHASE PRICE

The Company will pay the Seller monthly, for each kWh of Energy delivered and accepted at the Point of Delivery during the preceding calendar month, in accordance with the Standard Contract, an amount determined by the Seller's choice of one of the following options:

Option 1 - Fixed Price Method

Net Energy Purchase Price =

On-peak = (Fuel Cost + Capacity Cost) X Seasonality Factor
Off-peak = Fuel Cost X Seasonality Factor

where

Fuel Cost and Capacity Cost are the Avoided Cost Components established in this schedule for the applicable calendar year of the actual Net Energy deliveries to the Company.

Option 2 – Dead Band Method

Net Energy Purchase Price =

On-peak = (AGPU + Capacity Cost) X Seasonality Factor
Off-peak = AGPU X Seasonality Factor

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

Fuel Cost and Capacity Cost are the Avoided Cost Components established in this schedule for the applicable calendar year of the actual Net Energy deliveries to the Company, and

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

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

NET ENERGY PURCHASE PRICE (Continued)

Option 3 – Gas Market Method

Net Energy Purchase Price =

On-peak = (AGPU + Capacity Cost) X Seasonality Factor
Off-peak = AGPU X Seasonality Factor

Actual Gas Price Used (AGPU) = Indexed Fuel Cost

where

Capacity Cost is the Avoided Cost Component established in this schedule for the applicable calendar year of the actual Net Energy deliveries to the Company, and

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

CERTIFICATE OF SERVICE
UM 1129

I hereby certify that a true and correct copy of **DIRECT TESTIMONY OF JOHN R. GALE ON BEHALF OF IDAHO POWER COMPANY** was served via U.S. Mail on the following parties on February 27, 2006:

Bruce Craig
Ascentergy Corporation
440 Benmar Drive, Suite 2230
Houston TX 77060

Don Reading
Ben Johnson Associates
6070 Hill Road
Boise ID 83703

Thomas M. Grim
Cable Huston Benedict Haagensen & Lloyd LLP
1001 SW Fifth Avenue, Suite 2000
Portland OR 97204-1136

Steven C. Johnson
Central Oregon Irrigation District
2598 North Highway 97
Redmond WA 97756

Lowrey R. Brown
Citizens' Utility Board of Oregon
Suite 308
610 SW Broadway
Portland OR 97205

Jason Eisdorfer
Citizens' Utility Board of Oregon
Suite 308
610 SW Broadway
Portland OR 97205

Chris Crowley
Columbia Energy Partners
100 E 19th, Suite 400
Vancouver WA 98663

R. Thomas Beach
Crossborder Energy
2560 Ninth Street
Berkeley CA 94710

Irion Sanger
Davison Van Cleve PC
333 SW Taylor, Suite 400
Portland OR 97204

S. B. Van Cleve
Davison Van Cleve PC
333 SW Taylor, Suite 400
Portland OR 97204

Janet L. Prewitt
Oregon Department of Justice
General Counsel Division
100 Justice Building
1162 Court Street NE
Salem OR 97301

Michael T. Weirich
Oregon Department of Justice
General Counsel Division
100 Justice Building
1162 Court Street NE
Salem OR 97301

Mick Baranko
Douglas County Forest Products
PO Box 848
Winchester OR 97495

Randy Crocket
DR Johnson Lumber Co
1991 Pruner Road
PO Box 66
Riddle OR 97469

Elizabeth Dickson
Hurley Lynch & Re PC
747 SW Mill View Way
Bend OR 97702

David Hawk
J. R. Simplot Company
PO Box 27
Boise ID 83707

Linda K. Williams
Kafoury & McDougal
10266 SW Lancaster Road
Portland OR 97219-6305

Craig Dehart
Middlefork Irrigation District
PO Box 291
Parkdale OR 97041

Lisa C. Schwartz
Oregon Public Utility Commission
550 Capitol Street NE, Suite 215
PO Box 2148
Salem OR 97308-2148

Carel DeWinkel
Oregon Department of Energy
625 Marion Street NE, Suite 1
Salem OR 97301-3742

Laura Beane
PacifiCorp
Suite 800
825 NE Multnomah
Portland OR 97232

Data Request Response Center
PacifiCorp
Suite 800
825 NE Multnomah
Portland OR 97232

Mark Tallman
PacifiCorp
Suite 800
825 NE Multnomah
Portland OR 97232

Rates & Regulatory Affairs
Portland General Electric
1WTC0702
121 SW Salmon Street
Portland OR 97204

J. Richard George
Portland General Electric
121 SW Salmon Street
Portland OR 97204

Randall J. Falkenberg
RFI Consulting Inc.
PMB 362
8351 Roswell Road
Atlanta GA 30350

Peter J. Richardson
Richardson & O'Leary
515 North 27th Street
Boise ID 83702

Sarah J. Adams Lien
Stoel Rives LLP
900 SW Fifth Avenue, Suite 2600
Portland OR 97204-1268

John M. Eriksson
Stoel Rives LLP
201 South Main Street, Suite 1100
Salt Lake City UT 84111-4904

Brian Cole
Symbiotics, LLC
PO Box 1088
Baker City OR 97814

Thomas H. Nelson
Thomas H. Nelson & Associates
825 NE Multnomah, Suite 925
Portland OR 97232

Mark Albert
Vulcan Power Company
1183 NW Wall Street, Suite G
Bend OR 97701

Paul Woodin
Western Wind Power
282 Largent Lane
Goldendale WA 98620

Alan Meyer
Weyerhaeuser Company
698 12th Street, Suite 220
Salem OR 97301-4010

Bruce A. Wittman
Weyerhaeuser Company
Mailstop: CH 1K32
PO Box 9777
Federal Way WA 98063-9777

ATER WYNNE, LLP

/s/ Jessica A. Gorham
Jessica A. Gorham