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June 7, 2006

VIA EMAIL 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 – Idaho Power Company's Post-Hearing Brief

Dear Sir or Madam:

Enclosed for filing in the above-referenced docket are the original and five copies of Idaho Power's Post-Hearing Brief. Please contact me with any questions.

Very truly yours,

Wendy L. Martin

Wendy L. Martin

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'S

POST-HEARING BRIEF

June 7, 2006

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I. INTRODUCTION

In this Track 2 of Phase II, the Public Utility Commission of Oregon (the "Commission") will adopt guidelines for negotiations between investor-owned utilities ("IOUs") and qualifying facilities ("QFs") that exceed the 10 MW threshold for eligibility for a standard QF contract ("large QFs"). Specifically, the Commission will provide guidance as to the factors that may be considered in setting avoided cost prices for large QF contracts, and will consider certain contractual provisions identified in Order 05-584. In addition, the Commission will determine whether utilities may be required to purchase energy from large QFs at prices that fluctuate based upon spot market prices for natural gas.

Key to the Commission's determination is the substantial impact that large QF contracts will have on the utilities and their customers. The contracts at issue will be executed between utilities and QFs producing in excess of 10 MW—some may be in excess of 100 MW. Thus, the large QF contracts at issue in this portion of the docket will have a significantly greater impact on the utility's operations and finances and will pose a greater risk to the utility and its customers than the standard contracts considered in Track I. For a utility the size of Idaho Power, the impact could be enormous.

Accordingly, whereas in the case of standard contracts, policy considerations could allow the Commission to ignore the specific costs imposed by an energy purchase with a particular QF, in the case of the large QF, policy considerations tip in the other direction. When negotiating with a large QF, it is critical that the utility be allowed the freedom to negotiate terms and conditions that fully recognize and compensate the utility and its customers for all costs incurred by the utility in connection with the purchase. It is only in this way that the utility will be able to ensure that large QF contracts do not negatively impact utility customers.[1]

[1] The Commission recognized the different concerns posed by large and small QFs in Order 05-584: "With standard contracts, project characteristics that cause the utility's cost savings to differ from its actual avoided costs are ignored. No party presented evidence in this docket that the special characteristics of larger projects do not need to be considered in order to achieve rates that reflect actual avoided costs. Furthermore, the risk customers face because avoided costs in the future may be different from the prices paid under standard contract (through the Fixed Price Method, for example) is greater for a large QF than a small one." Order 05-584 at 16 (May 13, 2005).

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II. DISCUSSION

A. FACTORS TO BE CONSIDERED FOR AVOIDED COSTS

In 18 CFR §292.304(e), the Federal Energy Regulatory Commission ("FERC") provides a comprehensive (if not exclusive) list of factors which "shall, to the extent practicable, be taken into account" in determining avoided cost rates for QF contracts. In particular, subsection 292.304(e)(2) requires the utility to consider the following factors related to the availability of QF energy:

> The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:
>
> (i) The ability of the utility 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 utility's facilities;
>
> (v) The usefulness of energy and capacity supplied from the qualifying facility during system emergencies, including its ability to separate its load from generation;
>
> (vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and
>
> (vii) The smaller capacity increments and the shorter lead times available with additions from qualifying facilities.

Idaho Power will be commenting only on the most significant of these factors from the Company's point of view. However, it is clear that by enumerating this list of factors FERC

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intended that the utility calculate its avoided costs on as detailed as possible a level, taking into account all of the specific characteristics of the energy to be provided.[2]

1. Firm vs. Non-firm Energy

As suggested by the FERC regulations, availability and reliability are two of the primary characteristics affecting the value of energy to a utility. If the energy offered by a QF can be relied upon to be delivered in particular amounts at particular times, that energy generally will be substantially more valuable to the utility than energy that it cannot plan for or predict. For that reason, Idaho Power recommends that it be allowed to make clear distinctions between firm vs. non-firm energy and it be allowed to negotiate a system of prices and damages for non-performance that fully recognize reliability.

For some QFs, it makes sense to sell energy on a non-firm basis. For them, the ability to increase or curtail their energy deliveries at any time without prior notice and without economic consequence is a clear advantage that can and should be accommodated. For this reason, Idaho Power has an approved schedule in the state of Idaho, Schedule 86, which governs purchases and sales of non-firm energy from QFs. Non-firm energy as defined in Schedule 86 is energy sold by the QF to the Company on an "if, as and when available basis."[3] By basing the price of the energy sold under this tariff on published market prices, Idaho Power and its customers are assured that the prices paid for energy under the schedule reflect the real avoided

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[2] In this Track II, Weyerhaeuser/ICNU claims that Idaho Power's experience in Idaho demonstrates that QFs need assistance in negotiating contracts with utilities. Weyerhauser/ICNU points to the Company's own testimony that while it purchases from 71 QFs, almost all are under 10 MW. Weyerhauser/ICNU/300, Beach/10. From this Mr. Beach draws the conclusion that "in Idaho Power's service territory . . . it has made sense to develop QF projects that fall below the threshold for standard rates, so that one does not have to negotiate with the utility!" Weyerhauser/ICNU/300, Beach/11. Weyerhauser/ICNU provides no evidence to support this view. Their conclusion that utility intransigence is the primary reason that relatively few large QFs have developed in Idaho appears to be speculation.

While it may suit Weyerhaeuser/ICNU's purpose in this case to speculate that utility intransigence is the primary reason for the relatively few large QF developments in Idaho, a more logical conclusion would be that QF developers prefer the more lucrative standard rates and have simply chosen to downsize their projects to receive the higher purchase prices.

[3] Idaho Power Company, IPUC No. 26, Tariff No. 101, 3rd Revised Sheet No. 86-1.

cost to the utility. A copy of Idaho Power's Schedule 86 is filed as Exhibit 302 to the Direct Testimony of John R. Gale.[4]

Several of the QFs with whom Idaho Power has contracts in Idaho have chosen to sell under Schedule 86. These QFs recognize that, due to the uncertainty of their resource or operating plans, they are unable to commit to any level of energy output to the utility. In some cases, QFs have chosen to sell on a non-firm basis during the early start-up phase of a project; once they gain experience with their operations, they may opt to terminate the non-firm agreement (with no damages) and transition into a firm QF agreement in accordance with the applicable rules and regulations at that time.[5] For this reason, Idaho Power recommends that the Oregon Commission allow Idaho Power to file a similar tariff in Oregon, and be allowed to negotiate with larger QFs that desire to sell non-firm energy at market-based rates.

Of course, those QFs that have the ability to make firm commitments (as to the amount and timing of energy they will be able to deliver) will wish to enter into firm energy contracts that recognize the value of reliable and predictable energy. However, these firm energy contracts must provide for damages for failure to perform—just as in the case of any standard contract. Indeed, Idaho Power purchases hundreds of thousands of MWh each year from non-QF suppliers under firm contracts that provide for damages for non-performance. Without similar terms, utility customers will be disadvantaged by QF contracts.

Staff agrees that QFs entering into contracts to provide firm energy should be subject to damages for non-delivery or under delivery.[6] However, its definition of what constitutes firm energy differs substantially from Idaho Power's definition. That is, Staff recommends that in order to fulfill a contract to provide firm energy a QF need only fulfill annual—as opposed to monthly—commitments to provide firm energy.[7] As discussed in Phase II, Track 1 of this docket, this recommendation fails to recognize the utility's need to plan energy

[4] Idaho Power/302, Gale/1-7.
[5] Idaho Power/300, Gale/7.
[6] Staff/1800, Schwartz/6.
[7] Staff/1501, Schwartz/1.

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purchases to meet monthly, daily, and even hourly loads. An annual commitment simply does not suffice.

Accordingly, 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 damage provisions for a failure to perform obligations under the agreement and reasonable credit provisions to ensure that the large QF can actually pay damages to the utility if the large QF fails to perform.

Idaho Power acknowledges that the intermittent nature of some resources, such as wind or solar, 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 during the summer of 2006. 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.[8]

2. Dispatchability

There is no doubt that dispatchability is a significant benefit to the utility and that non-dispatchable energy is less valuable than dispatchable energy. Unfortunately, as Staff and Weyerhauser/ICNU note, many QFs have limited opportunity for utility dispatch.[9] As a result, much of the energy produced by QFs is less valuable to the utility than the proxy plant—which is assumed to be utility-owned and fully dispatchable. For this reason the avoided cost prices calculated for QFs must reflect the dispatchability or non-dispatchability of the resource. Idaho

[8] Idaho Power/300, Gale/9.
[9] Staff/1800, Schwartz/10; Weyerhauser/ICNU/300, Beach/13.

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Power recommends that the Commission allow it to use the same Integrated Resource Planning ("IRP") methodology as it uses in Idaho to estimate the cost of QF non-dispatchability.

Weyerhauser/ICNU recommends that purchase prices for both energy and capacity for large QFs be differentiated by time of delivery as an economic equivalent to dispatchability.[10] Idaho Power agrees that time-of-delivery ("TOD") pricing is appropriate for purchases from large QFs and that the Commission should encourage utilities and large QFs to utilize time-differentiated purchase rates in their negotiated agreements. Fortunately, with large QFs, economies of scale allow the cost-effective installation of sophisticated and reliable TOD metering and telemetry equipment. As a result, negotiated QF purchase prices can be differentiated seasonally, monthly, daily and even hourly without undue expense or difficulty.[11]

That said, contrary to Weyerhauser/ICNU's suggestion, TOD rates do not eliminate the need for contract provisions that address the reliability and dispatchability of large QF projects. Idaho Power's experience has shown that time-of-delivery pricing works best when it is used in tandem with contract provisions that operate to address reliability and ensure that customers are not disadvantaged by purchases from large QFs. As described by Company witnesses John Gale and Randy Allphin, these contract provisions are: (1) specified monthly minimum energy commitments; (2) remedies for failure to meet monthly minimum commitments; and (3) commercially reasonable security provisions to assure that large QFs will have the financial ability to make the utility whole if the QF fails to perform.[12]

Staff has suggested that the utilities consider the use of stochastic system dispatch models to estimate the cost of QF non-dispatchability.[13] Idaho Power has developed such a stochastic system dispatch model that it uses in its Integrated Resource Planning ("IRP") process. Running the system dispatch model ("IRP model") with and without the QF resource will provide cost information that can be used to determine the costs and benefits of adding a specific

[10] Weyerhauser/ICNU/300, Beach/13-14.
[11] Idaho Power/400, Gale-Allphin/2-3
[12] Idaho Power/400, Gale-Allphin/3.
[13] Staff/1800, Schwartz/11.

QF resource (size, dispatchability, location, etc.). This cost information can provide a rational basis for adjusting the avoided costs specific to the non-dispatchability of the individual large QF resource.[14]

In Idaho, the Company has been using this stochastic IRP method to calculate avoided cost rates for approximately ten years—since the Idaho Commission ordered Idaho Power and all other electric utilities subject to its jurisdiction to utilize their IRP models to determine avoided costs for large QFs.[15] This method provides a more precise measure of the value of an individual QF on Idaho Power's system than the generic standard rates and provides a cost-based framework for negotiations to address the price-related criteria the Commission identified in Order No. 05-584.[16] For all of those reasons, Idaho Power requests that the Commission allow Idaho Power to utilize the same IRP methodology it utilizes in Idaho to address the price-related criteria for negotiating avoided cost rates for large QFs in Oregon.

3. Separate Energy and Capacity Payments

Weyerhaeuser/ICNU recommends that purchase rates for large QFs be divided into separate payments for capacity and energy.[17] Idaho Power's experience in Idaho suggests that this proposal may raise more problems than it is designed to solve.

In its initial implementation of the Public Utility Regulatory Policies Act of 1978 ("PURPA") in Idaho, the Idaho Commission required that payment to QFs be structured as separate capacity and energy payments. As explained by Idaho Power in its testimony, the problems raised by separate capacity and energy payments became apparent early on when several QFs failed to provide the agreed-upon amounts of capacity. These early Idaho contracts contained provisions very similar to those recommended by Weyerhaeuser/ICNU in its Exhibit 302. Under these provisions, if a QF failed to provide the agreed-upon capacity, the QF was placed on probation, and if the QF could not correct the problem within a reasonable period of

[14] Idaho Power/400, Gale-Allphin/9.
[15] *Id.*
[16] Idaho Power/400, Gale-Allphin/11.
[17] Weyerhauser/ICNU/300, Beach13.

time, the QFs capacity was derated. When a derating occurred, the QF was required to refund the prior capacity overpayments. While those provisions are reasonable, the reality is that most QF developers utilize project financing to develop their projects and their projects have traditionally been highly leveraged.[18]

As soon as the QF project's capacity was derated and the obligation to repay the utility arose, the QFs complained to the Idaho Commission that they could not make their debt payments, cover O&M expenses, and repay the utility at the reduced revenue levels that were placed into effect after the QF's capacity was derated. After the Idaho Commission considered requests by QFs that the Idaho Commission require Idaho Power to provide fifteen- and twenty-year repayment terms so the QFs could maintain their cash flows, the Idaho Commission decided to eliminate the use of separate capacity and energy payments for future QF contracts. The Idaho Commission ordered that QFs be paid a rate that bundled the capacity and energy components into a single, per-kWh or "all-energy" rate. Eventually, most of the QFs that had separate capacity and energy payments opted to amend their contracts to utilize a single bundled payment rate.[19]

Given this experience, Idaho Power is reluctant to support the separation of energy and capacity rates.

Weyerhauser/ICNU argues that separate energy and capacity payments make sense because they provide incentives for reliability. For example, in his testimony Mr. Beach describes how a capacity payment based on delivery during on-peak times encourages a large QF to be available and therefore more "reliable."[20] He makes a similar argument for time-of-delivery energy payments.[21] However, combining those two payments into a single, per kilowatt-hour payment would provide an even greater level of incentive to a large QF to perform in accordance with its commitment. If the QF generates during the on-peak period, it will

[18] Idaho Power/400, Gale-Allphin/6-7.
[19] Idaho Power/400, Gale-Allphin/6-7.
[20] Weyerhaeuser/ICNU/300, Beach/12
[21] Weyerhaeuser/ICNU/300, Beach/13

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receive the on-peak capacity payment and on-peak energy payment combined. If the QF does not generate during the on-peak period, the QF will not only lose out on the energy component, but also the capacity component. This provides an even stronger incentive for the large QF to be reliable.

In summary, the bundled energy and capacity payments provide the same or greater incentive to perform without the problems of the large QF being paid for capacity not actually provided and the subsequent problems with derating and retroactive repayment mechanisms.[22]

For all of these reasons, Idaho Power urges the Commission to allow Idaho Power to pay avoided cost rates for large QFs utilizing a bundled energy and capacity rate.[23]

4. Competitive Bidding

While Idaho Power does not take the position that QFs should be *required* to participate in competitive bidding processes, it does believe that the results of any competitive bidding for similar resources must be considered in setting avoided cost prices for similar QF contracts.

There is no question that competitive bidding programs yield the best indication of the costs a utility can avoid by acquiring energy from a particular generation technology. Idaho Power's recent experience is instructive on this point. Idaho Power has 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 has issued an RFP for up to 100 MW of geothermal generating resources. As a result of the RFPs, Idaho Power will have current information from independent developers on actual costs of purchasing wind and geothermal resources at market prices that can be compared with administratively

[22] Idaho Power/400, Gale-Allphin/8.

[23] It should be noted that neither separate capacity and energy payments nor a bundled capacity and energy payment captures the additional costs Idaho Power incurs because large QF resources cannot be dispatched to optimize the overall cost of resources on Idaho Power's system. Weyerhaeuser/ICNU acknowledges that QF resources have very limited ability to change their generation patterns to respond to increasing customer loads or the availability of lower-cost alternative resources. Weyerhaeuser/ICNU/300, Beach/13.

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determined prices.[24] In order to ensure that customers are not harmed by large QF purchases the results of competitive bid processes must be considered in setting avoided cost prices for similar resources.

B. GAS SPOT MARKET PRICES

Weyerhaeuser/ICNU has 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.[25] For several important reasons, Idaho Power opposes this proposal.

First, the Weyerhauser/ICNU proposal would require Idaho Power to depart from the energy acquisition framework laid out in its Integrated Resource Plan ("IRP"). 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, nor does its most recent IRP include the construction or acquisition of a base-load generating resource fueled by natural gas. Indeed, the Company's 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, and the recent upward spikes in natural gas prices would seem to validate that decision. If, however, 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.[26]

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[24] Idaho Power/300, Gale/9.
[25] Weyerhauser/ICNU/300, Beach/24-26.
[26] Idaho Power/300, Gale/2.

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Second, allowing QFs the option of calculating avoided costs based upon monthly spot market prices for natural gas would impose an undue level of risk upon Idaho Power's customers. This concern was underscored recently when a developer 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 was approved by the Commission for small QFs in Order No. 05-584. Based on that inquiry, the Company performed a number of analyses designed to determine the impact on Idaho Power's customers of agreeing to purchase energy from the CHP at spot market natural gas rates.[27]

The details of these analyses are described in the Direct Testimony of John R. Gale, and Idaho Power Exhibit 301. The bottom line is that the Company's analysis revealed that entering into a contract to purchase energy from this QF using the Option 3 gas market methodology for the period January 2005 through January 2006 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 percent increase in customer costs that would have been incurred during the 13-month January 2005 through January 2006 period. This analysis did 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.[28] However, it is precise enough to conclude with certainty that gas market pricing would have harmed the Company and its customers.

Idaho Power also analyzed the same purchase using the Option 2 (gas dead-band method) standard rate methodology for the period January 2005 through January 2006. This analysis

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[27] Weyerhauser/ICNU/300, Beach/24-26.
[28] Idaho Power/300, Gale/2-4.

showed that Option 2 pricing 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.[29]

For these reasons, Idaho Power is opposed to using monthly natural gas price indices (either Option 2 or Option 3) to set purchase prices for energy generated by large QFs.

It is true that the Commission has determined that small QFs desiring to sell energy to Idaho Power can select Option 3 standard rates and receive purchase prices that vary monthly based on gas market prices. However, policy considerations weigh against application of the same requirements in the case of larger QFs. 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.[30]

Second, and 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 currently proposed would overwhelm the Company's total load in the state of Oregon.[31]

Weyerhauser/ICNU is candid about the fact that large QFs, particularly natural gas-fired CHP QFs, strongly desire to transfer the potential risks of volatile natural gas prices to the utility and its customers by tying QF purchase prices to spot market natural gas prices. As Mr. Beach notes, "With indexing, CHP projects gain the assurance of a direct link between the major cost

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[29] Idaho Power/300, Gale/4-5.
[30] Idaho Power/300, Gale/6.
[31] *Id.*

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driver of both their input and output costs, reducing operating risk and promoting more stable output."[32] However, Idaho Power decided not to a base-load natural gas-fired resource specifically in order to avoid natural gas price volatility risk.[33] Basing large QF purchase prices on fluctuating spot-market natural gas prices would unfairly shift back to Idaho Power's customers a gas price risk that should legitimately be borne by the QF developer. For this reason, the Weyerhauser/ ICNU proposal should be rejected.

C. LIABILITY INSURANCE FOR QFs UNDER 200 kW

Staff witness Michael Dougherty is recommending that utilities should not be allowed to require liability insurance coverage for QFs at or under 200 kW. Mr. Dougherty gives a number of reasons for this recommendation, including his opinion that the risk of liability is relatively low in comparison with the potential cost to the QF of obtaining insurance.[34] Staff's position should be rejected.

The cost of liability insurance may be more difficult to bear for a smaller QF than it is for a larger QF. However, that fact says nothing about the risk imposed by the smaller QF operations. Indeed, as explained by Idaho Power, the size of a QF facility is not related to the amount of 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.[35]

Moreover, Idaho Power's experience in Idaho would suggest that a liability insurance requirement does not serve as a barrier to smaller QFs entering into contracts. 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 percent capacity factor using Oregon Schedule 85,

[32] Weyerhauser/ICNU/300, Beach/25.
[33] Idaho Power/300, Gale/2.
[34] Staff/2100, Dougherty/4-12.
[35] Idaho Power/300, Gale 10.

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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.[36]

Mr. Dougherty argues that small QFs under 200 kWs might make a reasoned decision not to purchase liability insurance. He compares the decision to a homeowner who might make a reasoned decision not to purchase flood insurance if his or her home does not sit on a flood plain.[37] This comparison, however, is inapt. On the contrary, unlike flood risk, all QFs face liability risk. Idaho Power's primary motivation for requiring that liability insurance be in place is to protect Idaho Power and its customers from additional expense that it will necessarily incur defending itself in litigation if a QF is accused of negligence and a claim has resulted. Electrical contact injuries are often serious and the potential for economic damage is great. Invariably, in such a situation Idaho Power will be joined as a co-defendant in the lawsuit with the QF. If the QF does not procure liability insurance which requires the QF's insurance carrier to indemnify and provide a legal defense to Idaho Power, at a minimum the expense of defending the Company will be incurred by Idaho Power and ultimately visited on Idaho Power's customers, even if there is no actual recovery from Idaho Power.

Ultimately, leaving the decision as to whether or not to procure liability insurance to the QF developer is almost certainly going to result in many QF developers choosing to save money by foregoing the purchase of liability insurance. Allowing QF developers to make that decision will expose Idaho Power and its customers to potential expense and will also expose innocent third parties to the possibility of receiving an injury due to the negligence of the QF developer with no ability to collect their damages arising out of that injury for the QF developer. These exposures are not in the public interest.

Idaho Power should not be obligated to enter into contracts with QFs that are unwilling to purchase basic liability insurance. Such a requirement is inconsistent with prudent utility

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[36] Idaho Power/300, Gale/10.
[37] Staff/2100, Dougherty/5.

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practice and public policy.

III. CONCLUSION

In deciding the issues presented in this case the Commission must be mindful to maintain the careful balance at the heart of PURPA—namely to, in the Commission's own words, to "encourage the economically efficient development of [] qualifying facilities *while protecting the ratepayers by ensuring that utilities pay rates equal to that which they would have incurred in lieu of purchasing QF power*."[38] Implicit the Commission's formulation of these twin objectives is the assumption that by setting QF rates equal to that which the utility would have incurred in lieu of purchasing QF power—or, at avoided cost—the Commission will fulfill its obligation to encourage QF development.

Throughout the length of this docket, Idaho Power has urged the Commission to adopt policies that ensure that its customers will not be harmed by QF purchases. From the Company's perspective, Staff and the non-utility parties have at times encouraged the Commission to adopt policies that seek to grant advantages to the QFs to the detriment of the utility customers. To do so in this Track 2 of this docket, when considering policies that apply to large QFs, it would be particularly inappropriate for the Commission to do so. Instead, Idaho Power urges the

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[38] Order No. 04-584. Emphasis added.

Commission to reject any such requests and rather to encourage QF development in a fashion that will benefit not only the QF developers but also utility customers, and the public at large.

Respectfully submitted this 7th day of June, 2006.

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I hereby certify that a true and correct copy of **IDAHO POWER COMPANY'S POST-HEARING BRIEF** was served via U.S. Mail on the following parties on June 07, 2006:

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