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IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

U.S. GEOTHERMAL, INC., an Idaho corporation, Complainant, vs. IDAHO POWER COMPANY, an Idaho corporation, Respondent.	CASE NO. IPC-E-04-8
BOB LEWANDOWSKI and MARK SCHROEDER, Complainants, vs. IDAHO POWER COMPANY, an Idaho corporation, Respondent.	CASE NO. IPC-E-04-10

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

JOHN R. GALE

Q. Please state your name and business address.
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. Please describe your work experience.
A. In October 1983, I accepted a position as Rate Analyst with Idaho Power Company. In March 1990, I was assigned to the Company's Meridian District Office for one year where I held the position of Meridian Manager. In March 1991, I was promoted to Manager of Rates. In July 1997, I was named General Manager of Pricing and Regulatory Services. In March of 2001, I was promoted to Vice President of Regulatory Affairs. As Vice President of Regulatory Affairs, I am responsible for the overall coordination and direction of the Pricing & Regulatory Department, including development of jurisdictional revenue requirements and class cost-of-service studies, preparation of rate design analyses, and administration of tariffs and customer contracts. In my current position, I am responsible for policy matters related to the economic regulation of Idaho Power Company. I am also a member of

the Company's Risk Management Committee which is charged with balancing the Company's loads and resources on a short-term basis. Finally, in conjunction with the Company's Senior Vice President for Power Supply, I am sponsoring the Company's 2004 Integrated Resource Plan which assesses the Company's loads and plans for resources on a long-term basis.

Q. What topics will you discuss in your testimony in this proceeding?

A. I will explain why the Company has developed a standardized Firm Energy Sales Agreement ("FESA") that can be uniformly applied to all small qualifying facility ("QF") generating technologies.

I will explain why the Company is proposing to include provisions in the FESA that encourage QF developers to provide firm energy rather than non-firm energy. I will discuss the specific provisions the Company is proposing to include in the FESA to encourage greater "firmness" and explain why these provisions are fair to both QFs and to the Company's customers.

I will also discuss why the Commission needs to approve a standard methodology the Company can apply to determine if a particular QF project is larger than 10 MW. I will discuss the pros and cons of using either average annual energy or nameplate capacity to decide if a QF project is larger than 10 MW. I will also explain why the Company believes using metered energy amounts to determine whether or not a particular QF is larger than 10 MW is the best approach to this problem.

I will explain why the Company needs to include a contract provision that gives the Company the right to terminate QF contracts if electric utility industry deregulation prevents the Company from recovering stranded expense associated with above-market QF contracts.

I will also address other issues raised by Complainants' prefiled direct testimony.

Q. Why is the Company proposing a standardized contract for QF's smaller than 10 MW?

A. The Company has developed a standardized contract approach that can be applied uniformly to all QF projects with a capacity smaller than 10 MW regardless of generation technology. It works equally well for intermittent resources like wind and solar, resources with seasonal variations, like hydro and geothermal, and process-driven resources such as industrial cogeneration and biomass. This standardized approach simplifies the contracting process and provides economic incentives for the QF developer to accurately estimate the amount of energy it will provide each month. By providing economic incentives for QF developers to more accurately estimate the amounts of firm energy they will deliver each month, the Company is hoping to encourage QF developers to deliver firm energy rather than non-firm energy. Obtaining better estimates of the monthly amounts of firm energy to be provided will improve Idaho Power's ability to integrate QF resources into its resource planning and acquisition process as firm resources.

Idaho Power also believes that a key benefit of the Company's contract approach is that it allows intermittent QF resources such as wind and solar that are inherently non-firm an opportunity to be paid firm energy prices for at least a portion of their generation.

Q. Please describe the difference between firm and non-firm energy purchases.

A. Idaho Power's rate Schedule 86 governs purchases and sales of non-firm energy from QF's. 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, Third 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.

Idaho Power purchases hundreds of thousands of MWh's 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 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

Q. Aren't most of the 71 contracts Idaho Power has signed with QF's "firm energy" contracts?

A. The contracts Idaho Power signed with QF developers prior to 2003 describe the energy deliveries as "firm." In reality, the actual firmness of the energy deliveries under these pre-2003 contracts more closely resembles non-firm energy deliveries than firm energy deliveries. This is because there is no requirement for QF developers to actually deliver energy in the amounts and at the times they say they will in the Firm Energy Sales Agreement. As a result, the utility only has a general idea how much energy it can expect to receive from any QF at any time. The amount of energy delivered can fluctuate between 0 MW and 10 MW, hour to hour, day to day, month to month, completely at the discretion of the QF.

Q. If this type of contract has been the norm historically, why is the Company now seeking to improve the firmness or predictability of QF energy deliveries?

A. Conditions have materially changed since

1996, when the Company entered into the last Firm Energy Sales Agreements that did not require any monthly energy commitment from the QF developer. These changed conditions include: (1) Wholesale markets have standardized the terms and conditions of wholesale firm energy transactions. As a result, wholesale firm energy purchases from creditworthy counterparties are now generally accepted as a prudent and cost-effective way of meeting a portion of a utility's resource needs. Idaho Power's recent IRP's reflect that reality. (2) Idaho Power has changed from an energy-constrained company to a capacity-constrained company. Seasonal peaks require the Company to have a high degree of confidence that energy purchases will be delivered in the amounts and at the times specified to match seasonal peak energy demands. (3) Transmission constraints require that the Company more precisely anticipate its needs for firm energy imports. The ability to predict the output of resources within the utility's control area is increasingly important. (4) The growing prominence of intermittent generating technologies, such as wind and solar, require a new approach in the Company's PURPA contracting procedures. (5) The Company's increased use of firm market purchases as hedges to manage risk under its Commission-approved Risk Management Policy escalates the importance of predictable resource availability.

Q. Complainants' witness Dr. Reading testifies that QF contracts are "a mere drop in the bucket to a utility the size of Idaho Power." Does QF output really have any impact on Idaho Power's resource planning?

A. Yes. QF resources are no longer "a mere drop in the bucket to a utility the size of Idaho Power." (Reading, Direct, page 9). As a result of my involvement in the development of the Company's 2004 Integrated Resource Plan, it has become clear to me that Idaho Power's assumptions on QF output, especially during summertime peak-load hours, has a direct impact on Idaho Power's need for future resources. As I noted earlier in my testimony, Idaho Power has changed from an energy constrained company to a capacity constrained company. Idaho Power's need for additional resources is driven by transmission constraints encountered during summertime peak-hour load periods. Since almost of Idaho Power's QF's are located east of the Brownlee East constraint and inside Idaho Power's control area, QF output has a direct impact on Idaho Power's calculation of transmission deficits or transmission overload. Projected summertime transmission overloads will drive the need for new peaking resources.

During 2003, Idaho Power purchased about 75 aMW of QF generation, yet the nameplate capacity of the QF facilities under contract is 182 MW. Idaho Power is currently aware of approximately 200 MW (nameplate rating) of additional QF projects in various stages of development. that are interested in selling energy to Idaho Power. If these potential projects are combined with the existing QF projects currently under contract, the total is close to 400 MW. This is not an insignificant amount of capacity. The better that Idaho Power understands the month-by-month capability and projected out put of these projects, the better Idaho Power can assess its future resource needs.

Q. Can you summarize the contract provisions that Idaho Power has proposed to include in FESA's to provide the higher level of resource predictability you describe?

A. Yes. In Section 6.2 of the FESA, Idaho Power requests that the QF developer quantify the amount of Net Energy, in kilowatt hours, that the developer intends to deliver each month.

Q. When you cite a FESA Section number, what FESA are you referring to?

A. The section references in this testimony refer to the sections in the Draft FESA identified as Exhibit C to U.S. Geothermal's Complaint.

Q. Please continue.

A. Section 6.2.1 allows the QF developer to revise its monthly Net Energy amounts six months after the initial operation date, twelve months after the operation date, and then every two years thereafter. *At any time* the net energy commitment amount can be temporarily reduced (Section 6.2.2) if the project is affected by an event of force majeure or if the project experiences a forced outage (Sections 14.3.1 and 14.4.1).

As a result, Idaho Power's proposed FESA provides substantial flexibility to allow the QF developer to determine, based on its own judgment and experience, the amount of net energy that the project will commit to deliver each month, and provides flexibility to make adjustments to that commitment if unforeseen circumstances arise.

Q. Please continue.

A. Once the developer has determined how much energy it is comfortable in committing to provide each month, Idaho Power will include that firm energy amount in its resource planning and acquisition process.

If the QF developer subsequently delivers more energy in a month than Idaho Power had planned for, it is possible that Idaho Power will have to sell that energy in the surplus market or back-down a more economic production plant. If the QF subsequently provides less than the amount committed, it is possible Idaho Power would have to make additional firm purchases on the wholesale market to cover that shortfall.

To address that situation, the proposed FESA includes provisions to provide an economic incentive for the QF developer to actually deliver the amount of energy it indicated it would provide to the Company each month. If the QF delivers a monthly average amount of energy that exceeds 110% of the commitment amount, such excess energy (up to 10,000 kWh per hour) is purchased at the same rate the Commission has approved for non-firm energy purchases in Schedule 86. ("Surplus Energy", Section 1.2).

If the QF fails to deliver 90% of the energy it had committed to provide, *and that failure is not due to circumstances beyond its control, such as forced outages or force majeure events,* the proposed FESA provides for liquidated damages to compensate the utility and its customers for having to acquire energy to make up the shortfall. ("Shortfall Energy", Section 1.21).

Q. What do you mean by "events of force majeure" and "forced outages"?

A. Section 17.1 of the FESA is the *force majeure* section. If the QF developer is unable to meet its commitment amount as a result of events of force majeure (acts of God, etc.), its performance obligation is excused and any shortfall energy amount is reduced accordingly. In addition, Section 6.2.2 provides that if the QF facility experiences a forced outage during the month, any shortfall energy amount is appropriately reduced. Forced outages include generating equipment breakdowns, geothermal well breakdowns, Idaho Power line maintenance outages, etc. As a result, events that are truly beyond the control of the QF developer do not expose the QF developer to any liquidated damages.

Q. Does the FESA provide other limits on the QF's obligation to pay for energy shortfalls?

A. The FESA proposed by Idaho Power places reasonable limits on the QF developer's obligation to pay for shortfall energy in several ways. First, as noted above, if the QF project's failure to supply the 90% of committed energy is due to either force majeure conditions or a forced outage, Section 6.2.2 provides relief. Second, as provided in Section 1.9, the market price used to compute liquidated damages is only 85% of the monthly weighted average of the actual Mid-C prices. By using 85% of the monthly weighted average of the Mid-C prices, QF developers are immediately shielded from 15% of the actual Mid-C price. If 85% of the Mid-C market price is less than the monthly price in the FESA, the QF pays nothing. Third, Idaho Power has offered to limit the Complainants' shortfall exposure when 85% of the Mid-C market price is greater than the monthly FESA price by capping liquidated damages at 150% of the contract price. This protects the QF from extreme price run-ups such as those occurring in 2000-2001.

Q. Is this offer to cap the liquidated damages to 150% of the contract price contained in the FESA?

A. No. Idaho Power made this offer in letters to each of the Complainants dated May 21, 2004. Copies of the letters are attached as Exhibits 201 and 202.

Q. In their testimony the Complainants argue that requiring them to commit to a monthly firm energy amount is extremely unfair. Do you agree that requiring such a commitment is unfair?

A. No. While I can understand that the QF's would like to have complete discretion in scheduling energy deliveries, I do not believe it is unfair for Idaho Power to require some commitment on their part. All of the Complainants have testified that their projects are extremely reliable. The Complainants are in complete control of the amounts they commit to provide and Idaho Power will rely on the representations of the QF developer in making its resource and system planning decisions.

The FESA provides that if the project experiences events of force majeure or forced outages, the commitment level is adjusted to recognize those contingencies.

Q. Are there other measures that you believe make the commitment obligation equitable?

A. Yes. The commitment amount is a total monthly kWh amount. The QF is free to generate at maximum levels (up to 10,000 kWh per hour) for some hours during the month and generate at lower levels in other hours in order to meet the monthly commitment amount the QF chose.

In my mind, the only things that would subject the QF developers to shortfall energy payments is if their projections of monthly generation amounts are too high because they have overestimated the efficiency of their projects or equipment, or they assumed temperature variations that are not realistic or, in the case of the wind generation, the developers have overestimated the amount of wind that will be available. All of those estimates are completely within the control of the QF developers, not Idaho Power. In the case of U.S. Geothermal, a shortfall could also occur if U.S. Geothermal decided to divert energy from Idaho Power to serve other internal loads or to make sales to another entity who is willing to pay a higher price.

Q. Throughout their testimony, various Complainants' Witnesses refer to Idaho Power's proposed shortfall energy amount as a "penalty." Dr. Reading takes specific issue with Idaho Power's characterization of shortfall energy as liquidated damages. Could you address these criticisms?

A. I expect that Complainants' witnesses are repeatedly using the term penalty because they know courts generally do not enforce penalties in contracts. I believe that the Company's proposal to use average Mid-C pricing is not a penalty but is a reasonable way of computing liquidated damages.

Dr. Reading's brief definition of liquidated damages contained in his testimony is generally correct. Where Dr. Reading's analysis falls down is his assumption that the Company could precisely calculate the damages it suffered if the QF fails to deliver the agreed-upon amount of energy. Dr. Reading states: "First, the underlying reason for liquidated damage clause is missing. If a power supplier breaches its commitment to deliver power to an investor-owned utility such as Idaho Power, that IOU has tools readily at its disposal for calculating whether, and by how much, it is damaged."

I believe Dr. Reading is incorrect when he states that Idaho Power can readily calculate whether and how much it was damaged by the QF developer's failure to supply an agreed-upon amount of energy. First, the amount of energy shortfall is based on a monthly total. Idaho Power engages in numerous wholesale purchases and sales during a month. Sometimes Idaho Power makes purchases and sales simultaneously in an hour as a result of changed conditions, prior commitments, etc. The Company may also run different generating resources at different times during a month. If the QF developer has failed to deliver the required amount of energy in a month, would it be fair to allow Idaho Power to choose which transactions in the month it will attribute to the QF's failure to perform? Could the Company select, for example, all purchases at Palo Verde prices during heavy-load hours or all hours when Danskin is generating as the measure of its damages for the QF's failure to perform? I don't think that would be fair to the QF. At the same time, it is unfair to assume that the QF's failure to deliver has no cost impact on the Company's power supply expense. This is why a liquidated damages solution is the most equitable approach for both the utility and the QF.

Q. Complainants' witness Dr. Reading states that the fact that in 2002-2003 the QF's currently selling energy to Idaho Power provided approximately 70% to 75% of the energy they originally agreed to provide demonstrates QF projects are reliable. Could you please comment on this portion of Dr. Reading's testimony?

A. Dr. Reading correctly notes that in the aggregate the QF's selling energy to Idaho Power in 2002-2003 provided approximately 70% to 75% of the energy they originally agreed to provide. However, this statistic really does not provide much useful information on QF "reliability." The percentage only measures the difference between the QF developer's estimates of annual generation made 10 or 20 years ago and their actual generation for 2002 and 2003. In addition, the 70% figure Dr. Reading quotes is an average of all 69 projects currently selling energy to Idaho Power. In actuality, the percentage variation between developers' estimates and actual performance varies greatly by generation type. For example, in 2003 the thermal QF projects selling to Idaho Power delivered from 80% to 100% of the amount they estimated originally. The QF hydro projects using spring water or located on waterways with access to upstream storage generally (but not always) had higher levels of performance than did QF hydro projects located on rivers or creeks without upstream storage. Lumping the performances of all types of QF projects together and computing an average number for all of the different QF projects really does not provide much useful information to predict QF performance on a monthly basis. It is this monthly generation information that resource planners really need to make the most efficient resource acquisition decisions.

All of the Complainants in this case have testified as to how reliable they will be. Idaho Power has no way to independently assess the accuracy of those predictions. Under the contract form that Complainants desire to receive, there is no economic incentive to accurately estimate potential generation. As a result, for resource planning purposes, Idaho Power will never really know how much energy to expect from a particular QF in any month under these old-style contracts. That is one of the reasons Idaho Power is asking the QF developers to make a commitment to provide a firm amount of energy each month. Without such a provision, QF developers have no incentive to provide an accurate estimate of the energy they will actually provide.

Q. Complainants' witness Dr. Reading states that Idaho Power's proposal to require QF developers to commit to a monthly energy amount is intended to prevent the development of new QF's. Is he correct?

A. Of course not. Idaho Power included this requirement to encourage QF developers to provide firm energy in exchange for firm energy prices. As I noted earlier in my testimony, much has changed since the early 1980's. The types of resources Idaho Power needs, the ways Idaho Power plans to acquire resources and the ways it makes resource purchases is much different today than it was just a few years ago. I do not believe it is unreasonable for the Company to ask QF developers to accept reasonable contract requirements that enable the Company to integrate QF resources in today's resource planning and acquisition environment.

Q. Witnesses for both Complainants argue that by requiring them to contractually commit to a monthly energy amount, Idaho Power is requiring QF projects to comply with more stringent standards than its own projects are subjected to. How do you respond to this criticism?

A. The criticism is inaccurate. For example, on page 7 of his testimony, Dr. Reading states: "When a utility's own plant fails to produce or has an unscheduled outage, the ratepayers cover the cost associated with replacing the output from that plant. The shareholders are held harmless." In making that statement, Dr. Reading (1) inaccurately characterizes the operation of the Company's PCA mechanism; (2) fails to acknowledge the ongoing oversight by the Commission and its Staff; and (3) ignores the terms and conditions of the FESA.

Q. Why do you say Dr. Reading inaccurately represents the operation of the PCA?

A. Except for QF purchases between general revenue requirement proceedings, the Company only collects 90% of increases to its purchase power expense. The Company's shareholders bear a portion of the Company's purchase power risk and thus the Company is incented to make the best decision on every purchase transaction it undertakes. This risk sharing is not unlike the 90%-110% band Idaho Power has included in its FESA.

Q. Why do you say Dr. Reading fails to

acknowledge the ongoing oversight of the Commission and the Staff?

A. In each PCA proceeding, the Commission Staff closely audits the Company's power supply expenses. The most recent example of this oversight occurred in the Company's most recent PCA case. In Order No. 29506, the Commission cited the Staff audit and directed Idaho Power and the Staff to undertake additional analysis of a specific forced outage that occurred at the Valmy Plant last summer. Under the PCA specifically and as a regulated electric utility generally, the Company's operating practices and the costs of power from its generating plants are subject to prudency review on an ongoing basis.

Q. Why do you say Complainants' criticism ignores the terms and conditions of the FESA?

A. Complainants' testimony ignores material provisions of the FESA. On page 7, line 5, Dr. Reading states: "Idaho Power wants to have the best of both worlds by placing the risk of unscheduled outages on QF developers while enjoying the advantage of placing the risk of unplanned outages at their own plants on the ratepayers." In fact, in the FESA Idaho Power does *not* place the risk of unplanned outages on the QF developers. As noted above, force majeure events and forced outages reduce or eliminate shortfall energy amounts. (Section 6.2.2 and Section 17.1).

This includes outages due to Idaho Power line construction. (Section 6.2.2). Idaho Power is providing symmetrical treatment between QF contracts and Company owned generating resources.

Q. Are there other problems with Complainants' comparison of QF contracts and Company owned rate based plants?

A. Yes. Comparing a QF Firm Energy Sales Agreement to a utility's regulated generating resources is comparing apples and oranges. A utility-owned resource, once it is included in the utility's rate base and becomes operating property, is subject to ongoing regulation by the Commission in a number of ways. For example, the Company's return on its plant investment changes depending on the then-current rate of return allowed by the Commission. If the utility's costs of capital decline, the Company's return on its investment in generating facilities is reduced. This benefits customers. That's not the case for a QF project. Because the QF sells energy under a firm power purchase agreement and is not rate regulated, if interest costs decline, the QF can refinance its project at the lower debt cost and its equity owners retain 100 percent of the benefit of the refinancing.

Another difference between the utility's rate-regulated generating resource and the FESA power purchase agreement is that the utility's generating plant is dedicated to serve utility customer loads. Once the utility-owned generating plant becomes operating property, the utility does not have the right to sell the plant or direct the output away from serving its native load customers without commission approval. A QF is not so encumbered. For example, when Boise Cascade decided to close the Emmett mill and cancel the Emmett QF contract, it did so at the height of the Western Energy Crisis. The cancellation occurred at the only time during the life of the Emmett FESA that prices under the FESA were less than wholesale market prices. Our customers would have benefited if Boise Cascade had not cancelled the Emmett FESA. Boise Cascade paid the liquidated damages and immediately began to investigate if it would be cost-effective to operate the Emmett QF facility at the higher wholesale market prices. Ultimately they determined not to continue to generate at Emmett.

I provide this example not to criticize Boise Cascade. They did not cancel the Emmett QF FESA to take advantage of high wholesale electricity prices. But they did act in a manner consistent with their business interest without regard to the impact on Idaho Power or its customers. I believe this example illustrates a key difference between a utility resource dedicated to serve customer loads and a FESA.

I am not pointing out these differences to demonstrate that utility resource ownership is superior to a power purchase agreement with a QF. Both types of resource have a place in Idaho Power's resource portfolio. My only intent is to demonstrate that it is impossible to draw direct comparisons between a utility-owned, rate-regulated generating plant and a power purchase agreement with a QF. The appropriate comparison is between a firm energy purchase from the QF and a firm energy purchase from another creditworthy wholesale market participant.

Q. U.S. Geothermal Witness Runyan testifies that the contract provisions the Company is proposing to include to increase the firmness of the QF's commitment are inconsistent with PURPA avoided cost pricing. Do you concur with his analysis?

A. No. In considering Mr. Runyan's testimony, it is important to remember that PURPA provides that avoided costs are based on the costs the utility can avoid by purchasing from the QF rather than building a resource itself or purchasing additional resources on the wholesale market. (16 U.S.C. §824a3(d)). By including the firming provisions in the QF contracts, the Company is attempting to more closely align the firmness of energy purchases under the QF contracts with firm energy purchases it makes every day in the wholesale market. Idaho Power believes including contract provisions to encourage firm energy deliveries from QF's is consistent with PURPA.

Q. Do the FERC regulations implementing PURPA support the Company's position?

A. I believe they do. 18 CFR § 292, *et. seq.* are the FERC regulations which govern QF purchases. 18 CFR § 292.304(e) states in pertinent part:

> (e) *Factors affecting rates for purchases.* In determining avoided costs, the following factors shall, to the extent practicable, be taken into account:
>
> (2) The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:
>
> (i) the ability of the 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 a qualifying facility during system emergencies, including its ability to separate its load from its generation;

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

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

I believe that all of the provisions that Idaho Power is proposing to include in QF contracts are consistent with the factors described in subsection (2) stated above. The provisions are intended to increase Idaho Power's ability to predict when QF generation will be available so the Company can integrate QF generation into the utility's resource and system planning process. They are intended to increase the firmness and dispatchability of the QF resources. They are intended to define any sanctions for non-compliance. It certainly appears to me that what the Company is proposing to do is completely consistent with the intent of PURPA.

Q. You indicated previously that the Commission needs to decide how the Company will determine if a particular QF project is larger than 10 MW. Could you please explain what you meant?

A. The Commission has never definitively addressed how Idaho Power should determine if a particular QF project is a "less than 10 MW project" and therefore entitled to the published avoided cost rates. In 2002, in its Petition for Reconsideration, which was ultimately granted and led to the determination of the "published rates" in Case No. GNR-E-02-1, Idaho Power requested that the Commission designate "nameplate capacity" as the test the Company should apply to determine whether a QF project is entitled to receive the published rates. (Exhibit 203). The Commission did not address the Company's request in its final order, and as a result we still have no definitive Commission ruling as to the test to be applied to determine the capacity of a QF and its entitlement to the published rates.

Q. What is your understanding of the rationale for limiting the availability of published rates to QF projects 10 MW and smaller?

A. My understanding of the rationale supporting the differentiation between QF projects larger and smaller than 10 MW is a recognition that large QF projects may have individual characteristics that should be recognized in a negotiated contract between the utility and the QF. In addition, it is logical to assume that developers of large QF's will tend to be more financially sophisticated and the transaction costs associated with an individually negotiated QF contract would be more easily absorbed into the multi-million dollar costs of developing a large QF project. Conversely, it is also logical to assume that the developers of smaller QF projects may be less sophisticated developers and more sensitive to the transaction costs associated with individually-negotiated contracts, and as a result, standardized contracts and published rates would encourage small QF development. I believe these are generally logical assumptions and I support the Commission's decision to acknowledge the difference between larger and smaller QF projects.

Q. In the past, how has the Company decided which projects have a capacity greater than 10 MW?

A. Unfortunately, the process has been somewhat *ad hoc*. In most instances the Company used nameplate capacity as the test. Using nameplate capacity led to a succession of 9.9 MW QF projects being presented to the Company. In those instances the Company included a contract provision in the FESA's that put the QF developers on notice that if their 9.9 MW projects generated more than 10,000 kWh per hour, Idaho Power could declare that they were not entitled to the published rates. In the few instances where generation exceeded 10,000 kWh/hour, Idaho Power notified the QF's and the QF's immediately took steps to make sure that they did not generate more than 10,000 kWh per hour in the future.

The Company hopes that the Commission will use this case to establish the methodology the Company should use to determine which projects have a capacity less than 10 MW and are therefore entitled to receive the published rates.

Q. Why is it important that the Commission establish the methodology that defines the 10 MW capacity limit?

A. The recent Commission order in the *Renewable Energy* case has certainly increased Idaho Power's desire for certainty in this area. It would be in everyone's best interest if the Commission establishes a specific test that will identify those situations where the QF is larger than 10 MW and therefore the Company should use the AURORA model to compute avoided costs to be used to negotiate individual contracts with large QF's.

Q. Does the Company have a recommendation as to how the 10 MW threshold should be determined?

A. The Company believes that 10 MW is a measurement of capacity. As will be discussed later in my testimony, nameplate capacity rating is not very precise and annual average energy production is only indirectly related to capacity. The Company believes that using actual metered generation is the preferred method to determine if the capacity of a QF exceeds the 10 MW capacity limit. If a QF project's metering shows that the QF facility generated more than 10,000 kWh per hour, that facility's generating capacity must be greater than 10,000 kW or 10 MW. This test is simple, definitive and the least susceptible to manipulation of all of the tests. For purposes of my further testimony, I will refer to this test as the "Metered Energy Test."

Q. What are the various ways of measuring the capacity of QF projects?

A. Certainly the most commonly used measurement of a generating resource's capacity is the manufacturer's "nameplate rating." However, as U.S. Geothermal's Witness Kitz indicates on pages 9 and 10 of his testimony, "nameplate" rating means different things to different people. Nameplate rating can vary substantially from one machine to another simply based on the formula used by the manufacturer to compute the rating. For example, the nameplate rating of a generator at an 80% power factor is different from the nameplate rating of the same generator measured at a 90% power factor. In fact, a generator manufacturer can essentially say to a QF developer, "How much do you want it to be?", and be truthful depending on the test applied. Nameplate rating could be used to determine entitlement to the published rates if the Commission would specify a particular methodology to be used to measure nameplate rating.

The need to precisely define nameplate capacity is eliminated if the Company is permitted to use the metered energy test as a check against nameplate ratings. If energy purchases are limited to energy up to 10,000 kWh per hour, QF developers will have no incentive to "fudge" on the nameplate capacity rating.

Q. Please comment on U.S. Geothermal's suggestion that the Commission use annual average energy production to determine the capacity of its QF project?

A. The annual average energy test is only indirectly related to the engineering concept of generating capacity. It deviates too far from the Commission's use of 10 MW of *capacity* to be valid. For example, the average annual energy test would allow a QF project with a capacity of 100 MW to generate at its maximum rate of 100,000 kWh per hour for only 876 hours during the year and still qualify for the "less than 10 MW" rates. The average annual energy test would also allow a 30 MW QF project to contract to sell 10 aMW to each of three different utilities and qualify for the "less than 10 MW" rates from each of the three utilities.

While the initial reaction might be that these are extreme examples, in fact they are not. It is very likely that the Company will ultimately be presented with a wind project with an aggregate nameplate rating well in excess of 10 MW. In preparing its 2004 Integrated Resource Plan, Idaho Power has determined that the usual capacity factor for wind resources is approximately 35%. As a result, if the Commission adopts an average annual energy production test, very large wind projects that are creatively configured could qualify for the "less than 10 MW" rate. This would allow these large QF projects to bypass individual negotiations with the utility. This is exactly opposite of the result the Commission intended when it decided that QF projects larger than 10 MW should individually negotiate contracts with the utility.

Q. Are there other issues you want to address concerning Complainants' wind resources and QF resources in general?

A. Wind generation presents several significant problems for utility resource and system planners. Wind is an intermittent resource. It literally can fluctuate between zero and the machine's maximum capacity on a minute-to-minute basis. This fluctuation can be due either to periods when the wind does not blow or to periods when the wind blows so hard that the wind generating resource shuts off to protect itself. A wind resource is a good example of a non-firm, "if, as, and when available" resource. Wind resources, unless they are firmed by other dispatchable resources, simply cannot be described as providing firm energy. On a long-run average basis, wind energy may be as predictable as hydro generation. However, hydro generation is not subject to the instantaneous increases and decreases that wind generation is subject to.

Large intermittent resources also place significant demands on utility transmission and distribution resources. Tying up firm transmission capability on the Company's constrained system to accommodate intermittent generation from wind resources presents serious questions of prudency.

Q. Dr. Reading testifies on page 4 of his Direct Testimony that wind generators are entitled to be paid full avoided costs for all of their production. Do you concur?

A. Yes. Idaho Power believes that wind generation is entitled to be paid full avoided costs. The important distinction that must be drawn, however, is that wind-generated energy is *non-firm energy* and the full avoided cost for non-firm energy is not the published rate for firm energy. The appropriate full avoided cost for wind resources is a non-firm rate under the Company's Schedule 86.

Q. If that's the case, why is Idaho Power offering to pay firm energy prices for energy from the Lewandowski and Schroeder wind generators?

A. The FESA Idaho Power has proposed to Lewandowski and Schroeder (as well as to U.S. Geothermal) provides them with the opportunity to commit a portion of their projects total monthly energy generation as firm. If the amount they specify is actually provided, firm prices will be paid. Additional energy delivered up to 10,000 kWh per hour would be purchased at non-firm prices. The FESA Idaho Power has proposed places wind resources and all other QF resources on an equal footing and does not differentiate between technologies.

Q. U.S. Geothermal is requesting that the Commission rule that the Raft River Geothermal Project has a capacity of 10 MW or less and as such is entitled to the published rates. Does Idaho Power agree that the Raft River Plant has a capacity of 10 MW or less?

A. From the inception of its implementation of PURPA, the Commission has conditioned entitlement to published rates based on a measurement of capacity: 10 MW, 5 MW or 1 MW. As indicated earlier in my testimony, Idaho Power believes that the Commission's current orders referring to the 10 MW limit connotes 10 MW of capacity. U.S. Geothermal has indicated that its Raft River facility will have a combined generation nameplate capacity greater than 10 MW and will regularly generate more than 10,000 kWh per hour. Under either of those tests, the Raft River Plant will have a capacity that exceeds 10 MW.

However, because nameplate capacity rating is subject to so much variability, Idaho Power recommends that the Metered Energy Test be applied. This means that even if the nameplate capacity of the QF is larger than 10 MW, so long as the actual energy delivered in any hour does not exceed 10,000 kWh, the project should qualify for the published rates. This Metering Energy Test has worked well for Idaho Power in the past. It recognizes that nameplate capacity is a somewhat fluid definition. Using actual metered generation provides readily verifiable evidence of the actual generating capacity of a QF facility. This Metered Energy Test is included in the FESA's for the Horseshoe Bend Hydroelectric Project and the Magic West (Glenns Ferry) Cogeneration and Magic Valley (Rupert) Cogeneration Projects. Each of these three QF projects has a 9.9 MW nameplate capacity rating. These three FESA's were approved by the Commission on September 26, 1991 in Order No. 23946, January 22, 1993 in Order No. 24674, and July 23, 1993 in Order No. 25050, respectively. The metered energy test approach is also included in the contract between Idaho Power Company and the J.R. Simplot Company which is currently pending before this Commission.

If U.S. Geothermal is unwilling to agree to limit its deliveries for the Raft River facility to no more than 10,000 kWh per hour, then I believe the Raft River project fails the test for entitlement to published rates. In that event, it will be necessary for Idaho Power to use the

AURORA model to develop avoided costs to be included in a contract to be negotiated with U.S. Geothermal for the Raft River Project.

Q. Has Idaho Power utilized its AURORA model to compute avoided costs for the Raft River Project?

A. No. Idaho Power is hopeful that the Commission will use this case to make a determination as to the test to be applied to determine if a particular QF qualifies for the published rates. At this point Idaho Power does not know how the avoided costs that the AURORA model would compute for the U.S. Geothermal Project will compare to the published rates. If the Commission agrees with U.S. Geothermal's proposal to utilize average annual energy as the test for qualification for published rates, there would be no reason to go further. If the Commission determines that U.S. Geothermal's Raft River Project is larger than 10 MW and a negotiated contract is appropriate, Idaho Power would use the AURORA model to develop avoided costs and would expeditiously negotiate a Firm Energy Sales Agreement with U.S. Geothermal based on those avoided costs.

It seems to Idaho Power that it would be better for the Commission to make its determination of the proper capacity test regardless of whether its decision would result in a benefit or detriment to U.S. Geothermal.

Q. Complainants have objected to the Company's proposed contract provision addressing utility deregulation. Could you please discuss why Idaho Power needs a contract provision permitting it to terminate QF contracts if deregulation of the utility industry prevents the Company from recovering stranded QF contract expenses?

A. Yes. In the mid to late 1990s, led primarily by large industrial customers and potential independent power producers and energy marketers, such as Enron and CalPine, there was a strong push at both the state and federal level for restructuring the electric utility industry. In March of 1996 the Commission initiated a docket, Case No. GNR-E-96-1, in which the Commission considered the benefits and detriments of restructuring the electric power industry to separate generation, transmission and distribution, and to allow customers to choose their own electric suppliers without regard to exclusive utility service territories. In 1997 the Idaho legislature created an interim committee to study electric utility restructuring.

In each of those two forums, one of the more difficult problems discussed was the question of "stranded costs or stranded investment." In Idaho Power's case, its QF contracts represented a sizable share of the Company's potentially stranded costs.

Of course, there was a great deal of debate about whether Idaho Power would, in fact, have any stranded costs. A number of representatives of industrial customers and other argued that the market value of a number of Idaho Power's generation assets might exceed book cost, and if the above-market assets were less than the below-market assets, the utility would have no stranded costs. Dr. Reading espouses this view in his testimony on page 11.

Other mechanisms for recovering stranded costs that were discussed included exit fees, non-bypassable surcharges, and the issuance of bonds to reimburse the utility for its stranded costs. Under any of those scenarios, it is unlikely that the provisions of Section 23.2 would be triggered because the Company would, in fact, be fully compensated for its stranded QF expense.

However, during the course of the discussions on stranded costs, several parties argued that the electric utilities had been on notice for some period of time that the regulatory environment is in a state of flux and that the utilities have done nothing to protect their position. As a result, these parties asserted that the utilities have no right to claim an entitlement to stranded cost recovery. I recall that QF contracts were specifically mentioned as examples of stranded expenses that the utility could have addressed and had not done so.

Exhibit 204 is an excerpt from the report of the

Attorney General's Office to the 54th Idaho Legislature dated January 11, 1999, in which the Attorney General reported on electric utilities' restructuring. The highlighted portion on page 2 of Exhibit 204 discusses the argument that utilities can waive their right to reimbursement for stranded costs by failing to protect their rights today.

Obviously, it is impossible to know today whether, in some future electric industry deregulation process, the costs of Idaho Power's QF contracts will still be above-market and therefore constitute stranded expenses. It is not the purpose of my testimony to debate the merits or demerits of increased competition or the restructuring of the electric industry. If such restructuring occurs, it will likely come as a mandate from either Congress or the Idaho legislature. Idaho Power's only concern is, if it does occur, the Company needs to be protected from unfair results. Idaho Power is legally compelled to enter into QF contracts. It cannot refuse to enter into such contracts, even if it believes that the prices in QF contracts will exceed market prices over the long term.

Q. Complainant Witnesses Reading and Runyan both argue that the Commission approval of a QF contract is sufficient to protect the Company from stranded cost loss in the event of utility deregulation. Do you agree?

A. No, I do not. My legal counsel advises me that until the Commission issues an order either approving or disapproving the contract language Idaho Power has requested, the Company will be vulnerable to assertions that it voluntarily waived its rights to claim confiscation of its property if it cannot recover stranded QF expenses in the future.

Q. Do you have any comment on the testimony from the various Complainants' witnesses that allege that the Complainants will be unable to cost-effectively finance their projects unless the Commission rejects the contract provisions they identify in their Complaints?

A. On several occasions in the past, the Commission has ruled that Idaho Power is precluded from conducting discovery to examine the finances of a QF project. As a result, there is really no way for Idaho Power to determine the extent that such assertions may or may not be exaggerated. I can only note, however, that in the last six months the Company has entered into four FESA's with smaller QF's which FESA's contain all of the contested terms and conditions. To the limited extent Idaho Power is permitted to inquire, the Company has been advised that in the case of three of the four FESA's, it will be necessary for the QF developers to obtain project financing. The Company was further advised that in those three instances, all of the QF developers believed that they would be able to obtain project financing.

Q. Does this conclude your direct testimony?

A. Yes.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NOS. IPC-E-04-08/IPC-E-04-10

IDAHO POWER COMPANY

EXHIBIT NO. 201

JOHN R. GALE

IDAHO POWER
An IDACORP Company

IDAHO POWER COMPANY
P.O. BOX 70
BOISE, IDAHO 83707

BARTON L. KLINE
Senior Attorney

May 21, 2004

Conley E. Ward
Givens Pursley LLP
601 W. Bannock Street
P.O. Box 2720
Boise, ID 83701-2720

Re: Case No. IPC-E-04-8
U.S. Geothermal, Inc. v. Idaho Power Company, Raft River QF Project

Dear Conley:

The purpose of this letter is to advise U.S. Geothermal of several items that you will want to take into consideration in preparing U.S. Geothermal's testimony in the above-referenced complaint proceeding.

First, I don't believe there is any dispute that the U.S. Geothermal Raft River Project will have a nameplate capacity in excess of 10 MW. U.S. Geothermal has also indicated that there will be times when the Raft River Project will generate and deliver energy to Idaho Power at a delivery rate in excess of 10 MW. As a result, in this proceeding Idaho Power must take the position that the Raft River Project is not entitled to the published rates for QF projects smaller than 10 MW that are contained in the Exhibits to your complaint.

In accordance with the provisions of Commission Order No. 26576, Idaho Power will utilize the AURORA model to compute avoided cost rates for the Raft River Project based on the generation data provided in the complaint. It will be Idaho Power's position in this case that the Commission should not approve the rates contained in any of the Exhibits to your complaint but should approve rates computed using the AURORA computer model.

Idaho Power recognizes that U.S. Geothermal takes the position that it is entitled to the less-than-10 MW rates contained in your Exhibit A because, on an annual average basis, the Raft River Project generation will not exceed 10 MW. The purpose of this letter is not to argue that point but to make sure there is no misapprehension on U.S. Geothermal's part that Idaho Power is offering to purchase U.S. Geothermal's energy at the rates contained in Exhibit C to your complaint. It is not.

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Gale, IPCO

Telephone (208) 388-2682, Fax (208) 388-6936, E-mail BKline@i

Second, in its complaint, U.S. Geothermal objects to Idaho Power's proposed contract provisions contained in Exhibit C to your complaint that require U.S. Geothermal pay Idaho Power liquidated damages based on additional market purchase expenses Idaho Power may incur if U.S. Geothermal does not deliver 90 percent of the energy it has agreed to provide in any month (shortfall energy). U.S. Geothermal (and others) have expressed concern that this liquidated damage obligation could be prohibitively expensive.

Idaho Power has considered this concern further and is hereby offering to place a cap on U.S. Geothermal's liquidated damages exposure if U.S. Geothermal fails to provide 90% of the agreed-upon energy in any month. Idaho Power proposes to limit U.S. Geothermal's exposure in any month to a dollar per MWh amount equal to 150% of the net energy price for the month in which the shortfall occurs multiplied by the shortfall amount.

As an example of how this cap would operate, assume hypothetically that U.S. Geothermal had agreed to provide 6 MW (4,464 MWh) during the month of July. Further assume the contract price for net energy delivered in the month of July was $50 per MWh and the weighted average Mid-C market price in July was a highly abnormal $200 per MWh. If U.S. Geothermal only delivered 2 MW (1,488 MWh) in the month of July *and* the shortfall in energy delivery was not excused because of an event of force majeure or because a forced outage had prevented U.S. Geothermal from generating the full 6 MW (Paragraph 14.4, Exhibit C to Complaint), the shortfall would be 2,976 MWh (4,464 MWh less 1,488 MWh = 2,976 MWh shortfall). Using the assumed monthly weighted average Mid-C market price for energy of $200, the potential additional expense Idaho Power might incur as a result of this energy delivery shortfall would be ($200 - $50) x 2,976 MWh = $446,400.

However, Idaho Power is proposing to limit U.S. Geothermal's exposure to potential liquidated damages in two (2) ways. First, as provided in Paragraph 1.9 of Exhibit C to your complaint, the market price used is only 85% of the monthly weighted average of the actual Mid-C prices. By using 85% of the monthly weighted average of the Mid-C prices, U.S. Geothermal is immediately shielded from 15% of the actual Mid-C average price. As a result, using the above-referenced assumptions, the liquidated damage amount would be (85% x $200 - $50) = $120 x 2,976 = $357,120.

Second, the proposed 150% cap would further limit U.S. Geothermal's exposure. Applying the 150% cap, the liquidated damages amount would be (150% x $50) x 2,976 = $223,200.

Of course, using Mid-C market prices that are more in line with expectations shows that U.S. Geothermal's exposure is quite limited. For example – if the current month's contract price is $50 and the month's Mid-C weighted average was $58 or less, the Raft River Project would have no shortfall energy payment exposure because 85% x $58 = $49.30, and as stated in Paragraph 7.3 of Exhibit C, the calculated Mid-C price of $49.30 is less then the current month's contract price of $50 therefore no shortfall payment would be due from the project.

Coupling the 85% of Mid-C price limit with the 150% cap provides a manageable exposure if U.S. Geothermal fails to perform as agreed. Obviously the 150% cap exposes the Company and its customers to greater potential expense if U.S. Geothermal does not perform. The Commission will ultimately have to determine if assuming this additional exposure is in the public interest because it encourages the development of QF resources.

Finally, you should note that the Paragraph 23.2 offered to U.S. Geothermal by Idaho Power in Exhibit C is different than the description of Idaho Power's position contained in Paragraph 10 of the Complaint.

Idaho Power realizes that none of these items is likely to cause U.S. Geothermal to change any of its basic positions in this proceeding. Nevertheless, the Company thought it was appropriate to advise you of the positions Idaho Power will take in its testimony in this case.

Very truly yours,

Barton L. Kline

BLK:jb

cc: John Prescott
Peter Richardson
Scott Woodbury

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NOS. IPC-E-04-08/IPC-E-04-10

IDAHO POWER COMPANY

EXHIBIT NO. 202

JOHN R. GALE

IDAHO POWER
An IDACORP Company

IDAHO POWER COMPANY
P.O. BOX 70
BOISE, IDAHO 83707

BARTON L. KLINE
Senior Attorney

May 21, 2004

Peter J. Richardson
Richardson & O'Leary, PLLC
99 E. State Street, Suite 200
P.O. Box 1849
Eagle, ID 83616

Re: Case No. IPC-E-04-10
Lewandowski and Schroeder v. Idaho Power Company

Dear Peter:

The purpose of this letter is to advise you and your clients of a change Idaho Power is proposing to make to respond to one of the concerns raised in your complaint. Idaho Power will present this change as a part of its case in the above-referenced proceeding, and I wanted to advise you of this change so that you can take it into consideration in preparing your testimony.

In its complaint, Lewandowski-Schroeder ("Developers") object to Idaho Power's proposed contract provisions that require Developers to pay Idaho Power liquidated damages based on additional market purchase expenses Idaho Power may incur if Developers do not deliver 90% of the energy they have agreed to provide in any month ("Shortfall Energy"). Developers have expressed concern that this liquidated damage obligation could be prohibitively expensive.

Idaho Power has considered this concern further and is hereby offering to place a cap on Developers' liquidated damages exposure if Developers fail to provide 90% of the agreed-upon energy in any month. Idaho Power proposes to limit Developers' exposure in any month to a dollar per MWh amount equal to 150% of the net energy price for the month in which the shortfall occurs multiplied by the shortfall amount.

As an example of how this cap would operate, assume hypothetically that Developers had agreed to provide 6 MW (4,464 MWh) during the month of July. Further assume the contract price for net energy delivered in the month of July was $50 per MWh and the weighted average Mid-C market price in July was a highly abnormal $200 per MWh. If Developers only delivered 2 MW (1,488 MWh) in the month of July

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and the shortfall in energy delivery was not excused because of an event of force majeure or because a forced outage had prevented Developers from generating the full 6 MW (Paragraph 14.4, Exhibit A to Complaint), the shortfall would be 2,976 MWh (4,464 MWh less 1,488 MWh = 2,976 MWh shortfall). Using the assumed monthly weighted average Mid-C market price for energy of $200, the potential additional expense Idaho Power might incur as a result of this energy delivery shortfall would be ($200 - $50) x 2,976 MWh = $446,400.

However, Idaho Power is proposing to limit Developers' exposure to potential liquidated damages in two (2) ways. First, as provided in Paragraph 1.9 of Exhibit A to your complaint, the market price used is only 85% of the monthly weighted average of the actual Mid-C prices. By using 85% of the monthly weighted average of the Mid-C prices, Developers are immediately shielded from 15% of the actual Mid-C average price. As a result, using the above-referenced assumptions, the liquidated damage amount would be (85% x $200 - $50) = $120 x 2,976 = $357,120.

Second, the proposed 150% cap would further limit Developers' exposure. Applying the 150% cap, the liquidated damages amount would be (150% x $50) x 2,976 = $223,200.

Of course, using Mid-C market prices that are more in line with expectations shows that Developers' exposure is quite limited. For example – if the current month's contract price is $50 and the month's Mid-C weighted average was $58 or less, the Developers' project would have no shortfall energy payment exposure because 85% x $58 = $49.30, and as stated in Paragraph 7.3 of Exhibit A, the calculated Mid-C price of $49.30 is less then the current month's contract price of $50 therefore no shortfall payment would be due from the project.

Coupling the 85% of Mid-C price limit with the 150% cap provides a manageable exposure if Developers fail to perform as agreed. Obviously the 150% cap exposes the Company and its customers to greater potential exposure if Developers do not perform. The Commission will ultimately have to determine if assuming this additional exposure is in the public interest because it would encourage the development of QF resources.

Idaho Power realizes this is just one item in your complaint. Nevertheless, the Company thought it was appropriate to advise you ahead of time as to the position Idaho Power will take on this issue in its testimony in this case.

Very truly yours,

Barton L. Kline

BLK:jb

cc: John Prescott
Scott Woodbury

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NOS. IPC-E-04-08/IPC-E-04-10

IDAHO POWER COMPANY

EXHIBIT NO. 203

JOHN R. GALE

conclusion were not presented as a part of Staff's comments. As a result, none of the other Parties had an opportunity to examine the factual basis supporting Staff's conclusions. Because the Commission declined Idaho Power's and PacifiCorp's requests to convene a proceeding to consider current avoided costs, these parties were denied the opportunity to test the validity of Staff's analysis and conclusions cited in the Order. For the Commission's Order to cite the Staff's conclusion that the published rates are equivalent to current avoided costs (1) without any further discussion of that critical issue in the Order; (2) without giving the other Parties an opportunity to review and challenge the Staff's conclusion; or (3) without allowing other Parties to present evidence demonstrating that the published rates do *not* represent current avoided costs, is unreasonable and constitutes arbitrary and capricious decision making.

3. Order No. 29029 fails to specify how the 5 MW limit would be established.

In Order No. 29029, the Commission decided to increase the eligibility threshold for published rates from 1 MW to 5 MW. QFs larger than 5 MW would not be eligible for the published rates. However, Order No. 29029 does not specify how the 5 MW limit would be established. Idaho Power has already received inquiries from one QF developer with four separate qualifying facilities, all of which have a nameplate capacity rating that exceeds 5 MW. This QF is requesting that Idaho Power pay the published rates for 5 MW generated by a 11.2 MW rated facility and 5 MW generated by a 12.5 MW rated facility.

It is Idaho Power's position that the entitlement to published rates should be based on the nameplate capacity of the generating facility. Idaho Power believes

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that its position is consistent with the Commission's intent expressed in Order Nos. 25884 and 29029 that published rates are intended to facilitate the development of smaller QF projects that might feel that they were disadvantaged by having to negotiate project-specific rates with the utility.

Order No. 25884 issued January 3, 1995 in Case No. IPC-E-93-28 was the order in which the Commission established the current distinction between the avoided cost rates available to smaller or larger QF projects. In Order No. 25884 the Commission ordered that small QF projects could be eligible for published rates and large QF projects would negotiate avoided cost rates based on the individual characteristics of their project. The principal reason the Commission cited in Order No. 25884 to support its decision to establish published rates for smaller projects, was the concern that smaller project developers would be less capable of negotiating avoided cost rates with utilities. This same concern was echoed in Order No. 29029, i.e., the alleged "black box" cited on Page 6 of Order No. 29029. Idaho Power has found nothing in any Commission order to support a contention that it was the Commission's intent that the published rates would apply to a 5 MW portion of the generation from a qualifying facility larger than 5 MW. Construing Order No. 29029 in this manner would certainly defeat the intent expressed in Order No. 25884 requiring larger QF projects (above 5 MW) to negotiate project specific purchase prices with the utility based on the individual characteristics of the larger generation project.

4. <u>The Commission should order a stay of the effectiveness of Order No. 29029 to allow adequate time to update the assumptions in the existing methodology.</u>

BEFORE THE

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$0.50 of investment, unless some disposition is made somewhere, earns less than a reasonable return (here, 0%). Consequently, this portion of the investment has become stranded.[78]

"Negative stranded costs or investment" may also emerge. Instead of producing a decline in the economic value of generating facilities, competition may result in a net positive gain. Referring to the earlier simple example, it may be that the book value of the original $1 investment has declined to $0.25 (e.g., through depreciation), although the facility is fully functional. At the competitive market rate reflecting a return of $0.05 per unit/per period, the return on the residual book investment is 20%, implying an economic asset value of $0.50. The difference between the book and economic value (+$0.25) is sometimes termed a "negative stranded investment."[79] Some states both recognize the concept and require an offsetting of negative and positive values to determine the net amount of stranded cost recognizable for recovery.[80] For example, Montana Power Company recently sold most of its generating facilities for 155% of book value. In Maine, Bangor Hydro agreed to sell its hydro facilities for $89 million, when book value was about $50-$55 million.[81]

2. Should Stranded Investments be Recoverable?

As an initial matter, disagreement may exist whether stranded costs should be recognized at all. Theories [for] and [against] such recognition may be briefly summarized as follows:

- Social Compact Theory [For] -- Under this theory, investor-owned utilities undertook various obligations imposed by regulation 1) beyond or different from those warranted by ordinary free market considerations; 2) in order to address the public interest; 3) with an expectation that they would have a reasonable opportunity to recover those investments over time; and 4) over that period, the opportunity to earn a reasonable return thereon, as well. This theory derives from U.S. Supreme Court cases (Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591(1944); Bluefield Water Works v. West Virginia Public Service Commission, 262 U.S. 679 (1923); Smyth v. Ames, 169 U.S. 466 (1898)), which recognize that a company "is entitled to ask [for] a fair return upon the value of that which it employs for the public convenience" (Smyth, supra). Idaho's Supreme Court has adopted this principle.[82] More recently, the Court reiterated similar concerns in terms of the reasonable expectations of investors in Duquesne Light Co. v. Barasch, 488 U.S. 299 (1989).

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[78] FERC stranded costs are defined in terms of "wholesale stranded costs." See FERC Order No. 888 at 618-29.
[79] Fox-Penner at 397.
[80] See, e.g., Public Utilities Code, State of California, Chapter 2.3 "Electric Restructuring" Section 330(s): ". . . In determining the costs to be recovered, it is appropriate to net the negative value of above market assets against the positive value of below market assets" (hereinafter, "CPUC Code").
[81] Bangor Daily News (Sept. 29, 1998).
[82] Hayden Pines Water Co. v. Idaho PUC, 122 Idaho 356, 834 P.2d 873 (1992); Utah Power & Light Co. v. Idaho PUC, 102 Idaho 282, 629 P.2d 678 (1981); Intermountain Gas Co. v. Idaho PUC, 97 Idaho 113, 540 P.2d 775 (1975); In re Mtn. States Tel. & Tel. Co., 76 Idaho 474, 284 P.2d 681 (1955).

• Confiscation [For] -- This theory asserts the right of private property and the obligation to pay compensation in the case of governmental takings (U.S. Const. Amend. V: ". . . nor shall private property be taken for public use, without just compensation."). Historically, such arguments were sometimes allied with the due process clause, as well (Id: ". . . nor be deprived of . . . property, without due process of law"; *see* Smyth v. Ames, supra).

• Basic risk of business [Against] -- This theory asserts that all businesses are subject to the police powers of the state and to any necessary change in the exercise of those powers over time.[83] Where property remains in the owner's hands and can still be put to the production of income, no unlawful taking or confiscation occurs and no separate cost recognition or recovery is required. This is argued to be especially true of electric utilities, which have been on notice for some time that the regulatory environment is in a state of flux.

•Adverse competitive impacts [Against] -- In the view of some, recognition of stranded costs will unfairly advantage the incumbent utilities who benefit from such cost recovery, as against new competitors who receive no such compensation. In this regard, the D.C. Circuit in Cajun Electric Power Cooperative, Inc. v. FERC, 28 F.3d 173 (D.C. Cir. 1994), suggested two competitive concerns. First, that stranded cost recovery could effect a tying between stranded cost charges and charges for bottleneck transmission facilities. Second, stranded cost charges could result in competitive asymmetry, whereby the incumbent utility could compete outside its territory without paying the stranded cost charge, but all competitors within its territory would pay the cost charge to it.

• Public Policy [Against] -- This view asserts that recognition of stranded costs penalizes competitors and prudently run incumbent utilities for the efficiency of their operations, by rewarding inefficient utilities for past inefficiencies.

• Sharing principles [Intermediate] -- This approach suggests that stranded cost recovery mechanisms should require that amounts recovered by a utility for stranded costs be shared with consumers under certain circumstances (for example, when expected levels of stranded cost are not realized or when offsetting benefits are realized).

• Forced costs [Intermediate] -- Here, cost recovery would be permitted but limited to instances where affirmative regulatory mandates, initiated by the regulators, were the clear cause of the cost for which stranded recovery is sought. Some versions require such imposition to be over the active objection of the utility, as well.

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[83] Idaho's Constitution provides that "the police powers of the state shall never be abridged or construed as to permit corporations to conduct their business in such a manner as to infringe the equal rights of individuals, or the general well being of the state. Art. XI, § 8.

3. Types and Characteristics of Stranded Costs.

The pursuit of restructuring and competition in the states has led to an expanded scope of matters encompassed by stranded investment. Current inquiries and debates generally recognize three sources or types of stranded costs. They are:

1. Utility-owned generating facilities;
2. Long-term fuel and purchase power contracts, such as those arising from PURPA requirements;
3. Regulatory assets, including:
   - Deferred taxes;
   - Post-retirement employee benefits;
   - Nuclear decommissioning costs; and
   - Demand-side management (DSM) costs.[84]

Other types of costs may be also recognized for recovery purposes, depending upon the policies and goals of restructuring. For example, costs associated with environmental protection, natural resource preservation, and DSM address the public good. In a competitive market, however, unregulated sellers may choose not to incur these costs (such costs tend to produce no current income) and, thus, will obtain a price advantage over regulated utilities. As a result, the costs and the associated with these public benefits may, in a sense, become stranded.

FERC and related judicial proceedings have identified several criteria for characterizing costs as stranded. These characteristics may be summarized as: 1) prudently incurred; 2) legitimate; 3) verifiable; and 4) accurately calculated. From a different perspective, economic analysis may describe the essential characteristics of stranded costs in such terms as: 1) sunk in a prior period (before deregulation, actual or impending); 2) stranded by the transition to competition; and 3) not marginal in nature (since marginal costs are avoidable).

4. Measurement of Stranded Costs.

The measurement of stranded costs requires examination of the cost structure of each affected entity and econometric analysis of the affects of any given stranded cost recognition policy on resulting transition costs, residual utility investment, future utility revenues, and consumer price and choices. Stranded costs can be measured in several different ways, including:

a. Revenues Lost -- The volume of energy produced by a generation facility times the anticipated market price of that energy per unit (under regulation) is compared to the same output times the anticipated price under competition. The differential (if any) represents the amount of cost stranded by the transition to competition. Such computations can be based on projections (determined up front or ex ante) or upon

[84] Fox-Penner at 385-86.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on the 15th day of July, 2004, I served a true and correct copy of the DIRECT TESTIMONY AND EXHIBITS OF JOHN R. GALE upon the following named parties by the method indicated below, and addressed to the following:

Conley E. Ward Givens Pursley LLP 601 W. Bannock Street P.O. Box 2720 Boise, ID 83701-2720	____ Hand Delivered X U.S. Mail ____ Overnight Mail ____ FAX
Daniel Kunz, President U.S. Geothermal, Inc. 1509 Tyrell Lane, Suite B Boise, ID 83706	____ Hand Delivered X U.S. Mail ____ Overnight Mail ____ FAX
Peter J. Richardson Richardson & O'Leary PLLC 99 East State Street, Suite 200 P.O. Box 1849 Eagle, ID 83616	____ Hand Delivered X U.S. Mail ____ Overnight Mail ____ FAX
Don Reading Ben Johnson Associates 6070 Hill road Boise, ID 83703	____ Hand Delivered X U.S. Mail ____ Overnight Mail ____ FAX
Scott Woodbury Deputy Attorney General Idaho Public Utilities Commission 472 W. Washington Street P.O. Box 83720 Boise, ID 83720-0074	X Hand Delivered ____ U.S. Mail ____ Overnight Mail ____ FAX

BARTON L. KLINE