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IDAHO PUBLIC
UTILITIES COMMISSION

January 8, 2013

Ms. Jean Jewell
Commission Secretary
Idaho Public Utilities Commission
472 W. Washington
Boise, ID 83702

RE: GNR-E-11-03 – Petition for Reconsideration

Dear Ms. Jewell:

Enclosed please find the Petition for Reconsideration of J.R. Simplot Company, and Clearwater Paper Corporation. Per the Commission's Rules of Procedure, we have enclosed and original and nine (7) copies, as well as a copy for our office.

Sincerely,

Peter J. Richardson
Richardson & O'Leary PLLC

encl.

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Attorneys for J.R. Simplot Company, and
Clearwater Paper Corporation

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. GNR-E-11-03

IN THE MATTER OF THE COMMISSION'S REVIEW OF PURPA QF CONTRACT PROVISIONS INCLUDING THE SURROGATE AVOIDED RESOURCE (SAR) AND INTEGRATED RESOURCE PLANNING METHODOLOGIES FOR CALCULATING PUBLISHED AVOIDED COST RATES.	PETITION FOR RECONSIDERATION OF J.R. SIMPLOT COMPANY AND CLEARWATER PAPER CORPORATION

COMES NOW, J. R. Simplot Company and Clearwater Paper Corporation (individually "Simplot" or "Clearwater," and collectively "Petitioners"), and pursuant to Rule of Procedure ("RP") 331 of the Idaho Public Utilities Commission ("Commission" or "IPUC"), hereby respectfully requests reconsideration of the Commission's Order No. 32697. That order addressed several issues related to the Commission's implementation of the mandatory purchase obligations of the Public Utility Regulatory Policy Act of 1978 ("PURPA"). For the reasons set forth below, Petitioners respectfully request that the Commission reconsider and revise its determinations in Order No. 32697 as follows:

- Disavow use of the "singe-run" methodology for calculation of avoided cost rates for qualifying facilities ("QF") in the Integrated Resource Plan ("IRP") methodology, and instead require use of the IRP methodology proposed by Petitioners' witness, Dr. Don Reading; and
- Declare that QFs retain ownership of all environmental attributes, including renewable energy credits ("RECs"), when they sell QF energy and capacity to a utility at avoided cost rates calculated with the IRP methodology.

I.

PROCEDURAL AND FACTUAL BACKGROUND

The Commission entered its Final Order in this matter on December 18, 2012 (Order No. 32697). Among other issues addressed, the Commission determined that published avoided cost rates would be calculated utilizing a modified version of the Commission's long-standing surrogate avoided resource ("SAR") methodology. Order No. 32697 at 13-17. The Commission determined that these published rates will be unavailable for wind and solar QFs over 100 kilowatts ("kw") in capacity, as well as any other QF selling in excess of 10 average monthly megawatts ("MW"). *Id.* at 13. The Commission required use of the IRP methodology to calculate rates for QFs ineligible for the published avoided cost rates. *Id.*

Among the issues the Commission addressed in calculation of avoided cost rates in the IRP methodology, the Commission determined to adopt Idaho Power Company's ("Idaho Power") "single-run" methodology. *Id.* at 21. This was a drastic departure from prior practice, which substantially reduces the payment to QFs entitled to IRP-based rates.

With regard to ownership of environmental attributes or RECs, the Commission first determined that it had jurisdiction to resolve the dispute regarding treatment of non-energy environmental attributes in QF power purchase agreements ("PPA"). *Id.* at 44-45. Next, the Commission correctly stated that "there is no Idaho law that implements a renewable portfolio standard (RPS) program or addresses the ownership of RECs[,]" and correctly stated that "Idaho's avoided cost rates do not compensate QFs for RECs." *Id.* at 45. Thus, the Commission determined, "Because the SAR Methodology is based upon a gas-fired surrogate and such a resource produces no RECs, we find that it is reasonable and appropriate to assign the RECs for SAR-based QFs to the QFs." *Id.* at 46. Yet, by a confusing twist in logic, the Commission then determined, "Under the IRP Methodology, we find that splitting RECs either 50%-50% each year over the life of the PPA, or equally in terms of years over the length of the contract, is reasonable." *Id.* The Commission did not state that utilities must pay for their 50% share of the RECs generated by an IRP-based QF, and appears to have determined that the utilities will receive the RECs free of charge. *Id.*

Pursuant to IPUC RP 331, Petitioners hereby timely file this Joint Petition for Reconsideration. Petitioners operate QFs that are currently producing, or could be modified to produce, in excess of 10 aMW, and Petitioners may also seek to develop other QF resources in the future in excess of the eligibility cap for SAR-based rates. Petitioners are thus impacted by the Commission's determinations regarding the IRP methodology rates. Petitioners request that the Commission reconsider its determinations for the reasons set forth below.

II.

LEGAL STANDARD

IPUC RP 331.01 provides, "Petitions for reconsideration must set forth specifically the ground or grounds why the petitioner contends that the order or any issue decided in the order is unreasonable, unlawful, erroneous, or not in conformity with the law, and a statement of the nature and quantity of evidence or argument the petition will offer if reconsideration is granted." *See also* I.C. § 61-626.

III.

GROUNDS FOR RECONSIDERATION

This Petition seeks reconsideration regarding use of the "single-run" methodology for calculating avoided cost rates in the IRP methodology,[1] and the Commission's determination that the utility owns 50% of the environmental attributes or RECs when it purchases QF energy and capacity with rates calculated under the IRP methodology.[2] The nature and quantity of evidence or argument that the Petitioners would present on reconsideration is contained in this pleading and its attachments. Petitioners stand ready to present further briefing, oral argument, or any further technical testimony the Commission may request on the issues raised in this Petition.

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1 Petitioners do not request reconsideration of the Commission's other determinations regarding calculation of IRP methodology rates, including that QFs entering into contract renewals will be paid for capacity for the full term of the renewed agreement, that QF energy payments will not be discounted for transmission and line loss when a utility is energy surplus, and that the Commission will review capacity sufficiency determinations from the IRP. Order No. 32697 at 21-23.

2 Petitioners do not request reconsideration of the Commission's determinations that the Commission has jurisdiction to resolve the dispute between QFs and utilities regarding how QF PPAs should address ownership of environmental attributes, or that QFs paid with SAR rates will retain their environmental attributes. *See* Order No. 32697 at 43-46.

A. **The Commission Should Reconsider Order No. 32697 By Disavowing Use of the "Single-Run" Method for Calculating IRP Methodology Rates Because It Produces Rates Below the Full Avoided Costs.**

Federal law requires utilities to contract with each QF at the *full* avoided cost rates. The U.S. Supreme Court has upheld the Federal Energy Regulatory Commission's ("FERC") regulations requiring utilities to purchase capacity and output of QFs at full avoided cost rates. *Amer. Paper Inst., Inc. v. Amer. Elec. Power Serv. Corp.*, 461 U.S. 402, 413, 417-18 (1983); 16 U.S.C. § 824a-3(b), (d); *see also Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Pub. Util. Reg. Pol. Act of 1978* ("*Order No. 69*"), 45 Fed. Reg. 12,214, 12,222-12,223 (Feb. 25, 1980) (promulgating avoided cost regulations and directly rejecting proposals to provide QFs with rates at less than the full avoided cost); *Whitehall Wind, LLC v. Montana Pub. Service Commn.*, 355 Mont. 15, 21, 223 P.3d 907, 911 (2010) (reversing state commission determination of avoided costs because record on the whole demonstrated rates relying on stale data were below the actual avoided costs).

Order No. 32697 approved sweeping changes in how avoided cost rates are set using the IRP methodology. The Commission summarized this highly complex and multi-faceted issue as follows:

> Idaho Power proposed revisions to the IRP Methodology that focus on identifying the <u>incremental</u> costs that its system would incur, i.e., a single-run simulation, rather than its current methodology that is primarily predicated on making surplus sales at the future market prices developed within the AURORA model, i.e., a two-run simulation. In order to do this, Idaho Power proposes to use the AURORA model to determine the highest displaceable incremental cost being incurred during each hour of the QF's proposed contract term. The Company claims that its proposed modified methodology better aligns with the definition of avoided cost from federal regulations, and results in a much better estimation of the costs the utility is capable of avoiding.

Order No. 32697 at 21 (emphasis in original). One cannot discern from the Commission's discussion that any other party even addressed the issue. In fact, Dr. Reading on behalf of Clearwater, Simplot, and Exergy Development Group of Idaho, LLC and Don Schoenbeck on behalf of the Canal Companies[3] each extensively addressed this proposal and each reached separate conclusions that it is fatally flawed and contrary to PURPA. *See* Reading DI at 27-29; Schoenbeck DI at 17-21.

In its second paragraph addressing this issue, the Commission made the following findings:

> The Commission finds Idaho Power's proposed modifications to the IRP Methodology reasonable. We agree that the Company's revisions properly focus the determination of avoided costs on incremental costs, not solely on the value of potential market sales. The result, we find, is a more accurate avoided cost. Moreover, we find that the modified methodology comports with the definition of avoided cost contained in FERC regulations. Therefore, we direct Idaho Power, Avista and Rocky Mountain Power to utilize displaceable incremental costs in calculating avoided costs under the IRP Methodology.

Order No. 32697 at 21. Remarkably, in the immediately preceding section of the Order, the Commission found that, "the IRP models used by each individual utility produce reasonable avoided cost rates consistent with PURPA and FERC regulations." *Id.* at 20. Indeed, even Idaho Power's witness, Karl Bokenkamp, testified that the pre-existing IRP methodology "is a far more accurate approximation of avoided cost than the more generic SAR methodology." Bokenkamp DI at 6. Of course, the Commission continues to use the SAR methodology for all resources under 10 aMW and wind/solar under 100 kw, stating, "We acknowledge Idaho Power's efforts to devise an alternative wholly different than the SAR method currently used to obtain published avoided cost rates. However, we are not prepared to abandon the SAR method entirely." Order

[3] Twin Falls Canal Company, Northside Canal Company and the Renewable Energy Coalition.

No. 32697 at 14. The inconsistency is perplexing. While extolling the virtues of the pre-existing IRP methodology, Idaho Power proposed to devise a modification that substantially reduces the avoided cost rates. *See* Schoenbeck DI at 20 (containing a comparison of the rates calculated in the pre-existing IRP Methodology and the "single-run" methodology).

Idaho Power's proposal adopted by the Commission is summarized by Mr. Bokenkamp as follows:

> [T]he main difference is that in Idaho Power's current implementation of the IRP methodology, the QF generation supports market sales which generate revenues that reduce Idaho Power's calculated power supply costs, essentially valuing the QF generation at AURORA's estimate of future market prices with customers talking all of the price risk. Under the proposed methodology, the QF generation does not support surplus sales, it is simply valued at the highest displaceable incremental cost Idaho Power is incurring during the hour.

Bokenkamp DI at 21. Mr. Bokenkamp's rationale is rooted in a flawed reading of PURPA. Although he accurately quoted the definition of avoided costs, Mr. Bokenkamp posited that the avoided cost rate produced by the pre-existing IRP methodology is improperly predicated, in part, on making surplus sales at future market prices developed within the AURORA model. He made the following incredible legal conclusion:

> This deviates from the definition of avoided cost, which is focused on the incremental cost to an electric utility of displaced generation or purchases. Projected revenue from surplus sales is never mentioned in the federal regulation definition of avoided cost.

Bokenkamp DI at 7.

By restricting the definition of "cost" to exclude surplus sales *made possible* by QF purchases, Mr. Bokenkamp turns PURPA and traditional ratemaking on its head. Without those surplus sales that are only made possible by the QF purchase, Idaho Power would have lost an opportunity sale – which is a concept well established in electric utility ratemaking. The concept and quantification of lost opportunity sales is a concept that is commonly recognized in the PURPA context as well. In fact, much of Idaho Power's PURPA wind integration charge is based on lost opportunity sales due to the requirement imposed by that intermittent resource for higher reserves. The opportunity to make surplus sales at a profit is part and parcel with the reality of how Idaho Power runs its system, and is a well-known factor used by the Company in evaluating the benefit of future non-QF resources. Notably, Idaho Power has not proposed to use the "single run" methodology in its IRP planning process, where it will obviously prefer to consider the benefits of off-system sales its proposed utility-owned resources may provide.

Apparently the Commission put much stock in Mr. Bokenkamp's inventive definition of costs and failed to recognize the significance of surplus sales when it stated, "We agree that the Company's revisions properly focus the determination of avoided costs on incremental costs, *not solely on* the value of potential market sales." Order No. 32697 at p. 21 (emphasis provided). The order over-stated the record by asserting that the pre-existing IRP methodology is focused "solely" on potential market sales. Not even Mr. Bokenkamp's strained testimony went that far.

What Mr. Bokenkamp missed in his definition of cost is the key "but for" test concept in FERC's avoided cost rule, which states:

> Avoided costs mean the incremental cost to an electric utility of electrical energy or capacity or both which, *but for the purchase from the qualifying facility* or qualifying facilities, such utility would generate itself or purchase.

18 C.F.R. § 292.101(6) (emphasis added). In explaining this concept, FERC directly endorsed the two-run methodology Mr. Bokenkamp believed to be inconsistent with FERC's avoided cost rule. FERC stated:

> One way of determining the avoided cost is to calculate the total (capacity and energy) costs that would be incurred by a utility to meet a specified demand

> in comparison to the cost that the utility would incur if it purchased energy or capacity or both from a qualifying facility to meet part of its demand, and supplied its remaining needs from its own facilities. The difference between these two figures would represent the utility's net avoided cost. In this case, the avoided costs are the excess of the total capacity and energy cost of the system developed in accordance with the utility's optimal capacity expansion plan, excluding the qualifying facility, over the total capacity and energy cost of the system (before payment to the qualifying facility) developed in accordance with the utility's optimal capacity expansion plan including the qualifying facility.

Order No. 69, 45 Fed. Reg. at 12,216 (footnote omitted).

Mr. Schoenbeck succinctly addressed the problem with Idaho Power's proposal:

> [A]n appropriate method for establishing the rates for energy and capacity payments must reflect the cost that is avoided by purchasing the power from the QFs. The best manner to implement this fundamental avoided cost "but for" pricing principle is through employing two production cost simulations. With one simulation having the QF excluded from the resource mix and a second simulation with the QF in the resource mix, the difference in cost represents the costs that would have been incurred "but for" the QF. *The costs avoided due to the presence of the QF cannot be quantified under Idaho Power's single "QF-in" computer simulation.*

Schoenbeck DI at 18-19 (emphasis added). Mr. Schoenbeck did not equivocate; he simply and logically observed that under Idaho Power's single-run proposal it is impossible to calculate a utility's avoided costs due to the addition of a QF to its resource stack. Mr. Schoenbeck's conclusion is, in fact, the only reasonable conclusion. The result is fatally flawed without a comparison of the utility's *overall costs* to meet a specified demand before *and* after inclusion of the QF.

Dr. Reading provided extensive testimony on the ratemaking principles underlying marginal cost pricing in the context of setting avoided cost rates. These principles also weigh against Idaho Power's single-run methodology. Quoting from the leading authority on marginal cost pricing, Dr. Reading observed:

> Due to the fact that capacity is acquired in discrete blocks and long lead times are required, utilities will oscillate around the least total cost expansion curve. Rather than follow the short-run costs in their oscillations around equilibrium, *it is recommended that, for marginal costing purposes, the long-run marginal costs of generating capacity be used except in chronic cases of imbalance.*

Reading DI at 11 (emphasis in original).

The problem with Idaho Power's proposal is that it only calculates avoided cost rates on a very short run basis. As pointed out by Dr. Reading, this results in wildly inaccurate avoided cost estimates:

> In practical terms what this means is, over time, a utility will in the normal course of building plant to meet load almost always have surplus generating capacity. Because generation plant will be added in chunks that will exceed its shorter-term load needs it will thus almost always have a capacity surplus.

Reading DI at 11-12. Using the short-run marginal costing model to estimate long-term avoided cost rates deprives the QF of the benefit of having made the utility surplus at a time when excess generation could be sold at a profit. Dr. Reading noted that such a deprivation means that the QF will never be compensated "on an equal basis." Of course, this is the very same point that Mr. Schoenbeck made in stating that, "*The costs avoided due to the presence of the QF cannot be quantified under Idaho Power's single 'QF-in' computer simulation.*" Unfortunately, Order No. 32697 does nothing to address the conclusions from these two highly respected experts in this field that it is impossible for Idaho Power's single-run model proposal to even begin to approximate an accurate estimate of a utility's avoided cost rates. The resulting adoption of Idaho Power's "single-run" methodology will deprive IRP-based QFs of compensation at the full avoided costs. The Commission should disavow use of the single-run methodology.

B. The Commission Should Reconsider Order No. 32697 and Declare that QFs Retain Ownership of All Environmental Attributes and RECs When QFs Sell Energy and Capacity At Avoided Cost Rates Calculated with the IRP Methodology.

The determination in Order No. 32697 that the utilities will own 50% of the environmental attributes in an IRP-based contract is unreasonable, unlawful, erroneous, or otherwise not in conformity with the law for several different reasons. The reasoning violates PURPA by assuming that Idaho QFs are compensated for renewable attributes, by discriminating against QFs as opposed to non-QFs, and by imposing a new condition on large QFs' access to full avoided cost rates. Additionally, the order amounts to a physical taking of 50% of IRP-based QFs' RECs in violation of the Idaho and U.S. Constitutions. The order also violates the Dormant Commerce Clause of the U.S. Constitution by requiring in-state processing of a commodity the State of Idaho has not created – thus burdening the interstate flow of goods to benefit the Commission's chosen local proprietors. Furthermore, the reasoning arbitrarily disregards the Commission's past determination that a utility (Idaho Power) may not condition its federally mandated purchase of QF power on a *right of first refusal to also buy the QF's RECs* – which determination could only be construed as the equivalent of an order that Idaho Power *does not own the RECs.* Finally, the reasoning and outcome of the order cut against the Commission's duty to encourage QF development by undoing the financial benefits conferred on Idaho QFs by neighboring states' renewable portfolio standard ("RPS") laws.

1. Order No. 32697 is inconsistent with PURPA because it assumes that IRP-based rates compensate QFs for non-energy, renewable attributes, or otherwise provide favorable treatment to QFs that must be mitigated.

Idaho utilities must pay QFs the full avoided cost for their energy and capacity. *See* 16 U.S.C. § 824a-3(d); *Amer. Paper Inst., Inc.,* 461 U.S. at 413, 417-18. At the same time, however, avoided costs *do not compensate* the QFs for anything other than their energy and capacity. *See Amer. Ref-Fuel Co.*, 105 FERC ¶ 61,004 (2003). FERC has stated, "[t]he avoided cost rates, in short, are not intended to compensate the QF for more than capacity and energy." *Id.* at ¶ 22. FERC declared "contracts for the sale of QF energy and capacity entered into pursuant to PURPA do not convey RECs to the purchasing utility absent an express provision in a contract" or a rule of state law to the contrary. *Id.* at ¶ 24. "If avoided costs are not intended to compensate a QF for more than capacity and energy, it follows that other attributes associated with the facilities are separate from, *and may be sold separately from*, the capacity and energy." *Amer. Ref-Fuel Co.*, 107 FERC ¶ 61,016, ¶16 (2004), *den'g reconsid.* (emphasis added).

Order No. 32697 itself correctly acknowledged that "Idaho's avoided cost rates *do not compensate QFs for RECs*." Order No. 32697 at 45 (emphasis added). The order also correctly concluded that it is reasonable and appropriate to assign the RECs for SAR-based QFs to the QFs. *Id.* at 46. Because the avoided cost rates are not intended to compensate the QF for more than energy and capacity, the Commission's determination with regard to SAR-based rates was consistent with FERC's reasoning that "other attributes associated with the facilities are separate from, *and may be sold separately from*, the capacity and energy." *Amer. Ref-Fuel Co.*, 107 FERC ¶ 61,016, at ¶ 16 (emphasis added).

Yet Order 32697 nevertheless reasoned that the IRP-based rates compensate QFs for some of their RECs, or somehow compensate QFs for some of the costs associated with being a renewable facility, and thus deemed it proper to assign 50% of the RECs to the utility. *Id.* at 46. The order's string of logic is that IRP-based rates "are based on the actual generation characteristics of the renewable resource," and "Renewable resources, whether utility or QF owned, produce RECs." *Id.* at 46. Thus, the order stated, "we find it reasonable to equally apportion RECs between the utility and the QF." *Id.* The Commission further reasoned, "From the utility's perspective, selling RECs produces revenue which directly offsets the utility's (and ratepayers) costs of purchasing power from QFs." *Id.* This reasoning is inconsistent with PURPA because – just like the SAR-based rates – the IRP-based rates *only compensate for energy and capacity*. IRP-based QFs are entitled to the full avoided cost rates for their energy and capacity. There is no basis in PURPA to assume IRP-based QFs are compensated for renewable characteristics or that the Commission must mitigate the utilities' cost of purchasing energy and capacity at avoided cost rates.[4]

FERC itself has expressly stated so in a decision issued after the hearing in this proceeding. *See Morgantown Energy Assoc.*, 140 FERC ¶ 61,223 (Sep. 20, 2012), *deny'g recon.*[5] There, FERC addressed an order of the Public Service Commission of West Virginia assigning RECs in certain QF contracts to utilities. FERC noted that "the West Virginia Order, in fact, makes a number of express statements concerning the favorable nature of PURPA avoided cost rate contracts and how those favorable PURPA avoided cost rates support its finding that electric utilities should own RECs produced by QFs in the first instance." *Id.* at ¶ 19. FERC found such statements inconsistent with PURPA.

The reasoning of Order No. 32697 is substantively indistinguishable from the reasoning of the West Virginia Commission, and is likewise inconsistent with PURPA. For example,

[4] Indeed, as argued above, IRP-based QFs will be compensated for substantially less than the full avoided costs under the "single-run" methodology. This even further undermines the logic that there need be some rate mitigation for purchases from IRP-based QFs.

[5] This dispute has now progressed to the United States District Court for the Southern District of West Virginia (Case 2:12-cv-01809), where the QFs have commenced an enforcement action under Section 210(h) of PURPA.

FERC noted: "The West Virginia Order went on to note that the other states 'found that it was unfair for the utility customer to pay additional costs to purchase the credits . . . when they had already paid for the electricity at higher market rates to promote PURPA policies and the development of QFs[.]'" *Id.* at ¶ 19 n.39. Similarly, Order No. 32697 reasoned, "Splitting RECs under the IRP Methodology for wind/solar QFs larger than 100 kW and other QFs larger than 10 MW also *mitigates* those arguments that assigning RECs to either the QF or the utility in their entirety represents *a revenue windfall* to the recipient." Order No. 32697 at 47 (emphasis added). A QF's receipt of payment for its RECs is not a windfall; it is compensation for the sale of an attribute other than the energy and capacity it sells to the utility.

In another passage, FERC explained:

> It is likewise significant, we find, that the West Virginia Commission implied that RECs produced by non-QFs could be considered to be owned by the non-QF generator in the first instance rather than the first purchaser of the output of the non-QF generator. The only reasonable reading of the West Virginia Order is that the West Virginia Commission's finding that RECs produced by QFs, as opposed to RECs produced by non-QFs, are owned by the purchasing utilities in the first instance is based on the West Virginia Commission's belief that the PURPA avoided cost rates are overly generous and therefore must include RECs.

Morgantown Energy Assoc., 140 FERC ¶ 61,223 at ¶ 21. FERC ultimately concluded that "the West Virginia Commission cannot, consistent with PURPA, assign ownership of the RECs to the Utilities on the grounds that the avoided cost rates in their PURPA PPAs compensate the QFs for RECs in addition to energy and capacity." *Id.* at ¶ 24. But that is just what Order No. 32697 did in this case when it reasoned IRP-based rates "are based on the actual generation characteristics of the renewable resource," and "Renewable resources, whether utility or QF owned, produce RECs." Order No. 32697 at 46. It is inconsistent with PURPA to then conclude utilities should own some of the RECs because IRP-based rates compensate QFs for some of their RECs, or somehow compensate QFs for some of the costs associated with being a renewable facility. The IRP Methodology calculates the *value of the energy and capacity* to the utility – not the value of any renewable attributes of the generation.

The Commission's order appears to have confused FERC's precedent. FERC has indeed ruled that a state utility commission may require a utility to pay a separate, *higher* avoided cost rate stream for QFs that will help the utility avoid actual costs of a resource procurement requirement in addition to the providing energy and capacity. *Cal. Pub. Util. Commn.*, 133 FERC ¶ 61,059 (2010), *grant'g clarify. and dimiss'g reh'g*. However, because Idaho law imposes no renewable procurement requirement, this reasoning is inapplicable in Idaho. The utilities are only compensating IRP-based QFs for energy and capacity – not any costs associated with a renewable resource procurement requirement. Thus there is no basis in Idaho law or the Commission's implementation of PURPA to transfer RECs to the utilities.

The Commission had it right the first time, when it stated "Idaho's avoided cost rates do not compensate QFs for RECs." Order No. 32697 at 45. This is the case for IRP-based and SAR-based QFs. And it follows that even IRP-based QFs retain all of those RECs.

2. Order No. 32697 violates PURPA by discriminating against QFs as opposed to other non-QF generators.

FERC's regulations generally require that QFs be treated in a non-discriminatory manner. *See* 18 C.F.R. § 292.304(a)(1)(ii), § 292.306(a). With regard to REC-ownership, FERC has stated, "[W]hile *a state may decide that a sale of power at wholesale automatically transfers the ownership of the state-created RECs*, that requirement must find its authority in state law, not PURPA." *Morgantown Energy Assoc.*, 140 FERC ¶ 61,223 at ¶ 24 (emphasis added). The problem with Order No. 32697 is that Idaho law does not declare that a sale of power at wholesale automatically transfers the ownership of Idaho's *state-created* RECs.[6] Nor does it even-handedly apply to QF and non-QF generators in the state. Instead, it sets up a regime where large QFs receiving IRP-based rates must transfer 50% of their RECs, while large non-QF generators may retain and sell separately all of their RECs or sell their RECs bundled with the electrical output for additional compensation.

This is demonstrated by a recent non-QF contract approved by the Commission – the Neal Hot Springs Geothermal contract. *See* Order No. 31087. Petitioners have attached this approved contract and order as Attachment 1. In approving the agreement, the Commission noted "the Agreement is not a PURPA contract." *Id.* at 2.[7] The Commission expressly noted, "Although the energy costs for the Neal Hot Springs facility are higher than current PURPA rates, the Agreement provides benefits to Idaho Power as identified by the Application. For example, Idaho Power will receive ownership of all renewable energy credits associated with the facility, and *this clearly will provide value to Idaho Power*." Order No. 31087 at 4 (emphasis added). There is no law requiring this non-QF to gift any portion of its RECs, and it therefore negotiated a higher rate than the mere value of its electrical output (which is by definition the avoided cost rates) in exchange for also selling its RECs.

Under the reasoning of Order No. 32697, IRP-based QFs selling to the same utility cannot do this. Instead, IRP-based QFs must cede half of their RECs for no additional payment. Discrimination occurs because unlike large QFs, large non-QF generators do not automatically transfer half of their RECs to the purchasing utility. Rather, because they retain all of their

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6 Indeed, Idaho law does not even create any such RECs; they exist because neighboring states enacted laws allowing RECs to be produced by QF and non-QF generators in Idaho.

7 *See also* FERC Docket No. ER13-413 (containing the generator's application to sell as an exempt wholesale generator at market based rates). A non-utility generator that is not a QF must obtain status as an exempt wholesale generator from FERC in order to avoid regulation as a public utility.

RECs, non-QFs can negotiate a better rate to sell electricity bundled with all RECs, or may retain unbundled RECs and sell them separately. In effect, the order punishes large QFs for utilizing the mandatory purchase provisions of PURPA. This violates PURPA by discriminating against QFs.

3. Order No. 32697 violates PURPA by conditioning an IRP-based QF's access to full avoided cost rates on the QF's agreement to give away half of its RECs – thus imposing a pre-condition for the benefits of QF status found nowhere in FERC's regulations.

All QFs have the option to sell energy and capacity to a utility and to receive compensation at the full avoided cost rates for that energy and capacity. *See Amer. Paper Inst., Inc.,* 461 U.S. at 413, 417-18. However, Order No. 32697 imposes a new regime, whereby a large QF in Idaho may only sell to a utility at the avoided cost rates if that QF agrees to sign a contract granting the utility ownership of 50% of the QF's RECs. This creates an illegal precondition on the QF's entitlement to full avoided cost rates.

In an analogous situation, the California Public Utility Commission attempted to use certain efficiency standards as a precondition to QFs' access to full avoided cost rates. The Ninth Circuit held that PURPA preempted this precondition to payment at the full avoided costs. *See Ind. Energy Producers Ass'n, Inc. v. Cal. Pub. Util. Commn.*, 36 F.3d 848 (9th Cir. 1994). The Court explained:

> The CPUC program usurps the [FERC]'s authority by authorizing the Utilities to determine whether a QF is in compliance with federal efficiency standards. It also violates PURPA by substituting for any "non-complying" QF an "alternative" avoided cost rate equal to 80% of the Utilities' avoided cost for short term economy energy. QFs are entitled to receive the full avoided cost rates provided in the QF's standard offer contract, 18 C.F.R. Sec. 292.304, and not a rate that is 80% (or less than 80%) of the full avoided cost rate. *The CPUC program thus authorizes the Utilities to deny to QFs one of the benefits to which they are statutorily entitled under PURPA, resulting in the effective decertification of that*

QF. Because the authority to make QF status determinations resides exclusively with the Commission, we conclude that the CPUC program is preempted by federal law.

Id. at 854-55 (emphasis added) (footnote omitted).

The same outcome will unfold in Idaho if utilities can condition access to avoided cost rates on an IRP-based QF's ability, or agreement, to cede 50% of its RECs. It is now common for parties to pre-sell forward strips of several years of RECs. However, if a QF had pre-sold its RECs in a long-term forward strip prior to entering into the PPA, that QF would be unable to comply with the requirement in Order No. 32697 that it convey 50% of the RECs to the utility. It is also possible that certain QFs will be structured financially such that the entity responsible for generating electrical output and contracting with the utility for sale of that output is not the entity that owns all of the renewable attributes of the facility. This is a likely scenario in the case of renewable fuel supplier at a dairy, landfill or biomass plant that wishes to retain the renewable benefits of selling the fuel, which could include both RECs and carbon offsets. In that case, the QF – despite meeting all of FERC's qualification criteria – would be unable to sign an Idaho PURPA PPA without restructuring its entire organization. And the utility would obviously refuse to purchase the QF's output at the full IRP-based avoided cost rates if the QF cannot cede 50% of its RECs. The QF might be able to negotiate a rate that was less than the full estimate of the avoided cost rate, for its inability to also convey its RECs. But in either scenario the effect is inconsistent with PURPA because the state requirement curtails the QF's right to receive full avoided cost rates for energy and capacity due to a condition found nowhere in FERC's regulations.

4. Order No. 32697 effects a taking in violation of the Idaho and U.S. Constitutions by gifting 50% of an IRP-based QF's RECs to the utility.

Order No. 32697 itself acknowledges that Idaho avoided cost rates do not compensate for RECs, yet the order nevertheless gifts 50% of the IRP-based QF's RECs to the utility. The Fifth Amendment of the U.S. Constitution and Article 1 Section 14 of the Idaho Constitution each provide that private property shall not be taken for public use without just compensation. U.S. Const. amend. V, cl. 4; Idaho Const. art. 1 § 14. The purpose of the takings clause is to prohibit the "Government from forcing some people alone to bear public burdens which, in all fairness and justice, should be borne by the public as a whole." *Armstrong v. U.S.,* 364 U.S. 40, 49 (1960). Courts first examine whether the claimant possesses a property interest that is protected by the Fifth Amendment. *Ruckelshaus v. Monsanto Co.,* 467 U.S. 986, 1003-04 (1984). If such an interest is established, courts then examine whether the government's action amounts to a compensable taking of that interest. *Id.* at 1005-06. When such a taking occurs, an aggrieved individual may file a claim for "inverse condemnation," which is a shorthand description of the manner in which a property owner recovers just compensation for a taking of his property when condemnation proceedings have not been instituted. *U.S. v. Clarke,* 445 U.S. 253, 257 (1980).

a. RECs are compensable property rights.

For purposes of Takings Clause analysis, "property" refers to "the group of rights inhering in the citizen's relation to the physical thing, as the right to possess, use and dispose of it." *U.S. v. Gen. Motors Corp.*, 323 U.S. 373, 377-78 (1945); *see also Lingle v. Chevron U.S.A. Inc.*, 544 U.S. 528, 539 (2005); *Loretto v. Teleprompter Manhattan CATV Corp.*, 458 U.S. 419, 435 (1982). Property interests "are about as diverse as the human mind can conceive." *Flor. Rock Indust. v. U.S.,* 18 F.3d 1560, 1572 n. 32 (Fed.Cir.1994). The Takings Clause "is addressed to every sort of interest the citizen may possess." *Gen. Motors Corp.*, 323 U.S. at 378; *see also Lucas v. S.C. Coastal Council,* 505 U.S. 1003, 1019 (1992) (real property); *Monsanto Co.*, 467 U.S. at 1003-04 (intangible trade secret property); *U.S. Trust Co. v. New Jersey*, 431 U.S. 1, 19 n.16 (1977) (contract rights); *Members of the Peanut Quota Holders Ass'n v. U.S.*, 421 F. 3d 1323, 1332 (Fed. Cir. 2005) (government issued peanut quotas); *Roth v. Pritikin,* 710 F.2d 934, 939 (2d Cir.1983) (copyright); *Redevelopment Authority of Philadelphia v. Lieberman,* 336 A.2d 249, 257-59 (Pa. 1975) (liquor license).

Order No. 32697 does not even appear to contest that RECs are a compensable property interests that are separate and distinct from the energy and capacity sold in a PURPA PPA. As noted repeatedly above, the avoided cost rates do not compensate QFs for RECs or other environmental attributes. Indeed, both Petitioners currently have PPAs wherein they contracted to sell their QF electrical output at the avoided cost rates but retain the right to separately convey the unbundled renewable attributes of the generation. *See* Attachment 2 (Simplot PPA and IPUC order approving it); Attachment 3 (Clearwater PPA and IPUC order approving it). There can be no doubt that a QF's right to separately transfer the RECs is a compensable property right.

b. Order 32697 Requires IRP-based QFs to Gift Environmental Attributes to the Utilities, and Therefore Constitutes a Physical Taking.

Order No. 32697 appears to have reasoned that no taking occurs because the IRP-based QFs will still own 50% of their RECs, or perhaps that nobody owned Idaho RECs prior to the Commission's order. *See* Order No. 32697 at 47. This reasoning is indefensible. Idaho has still not created any *state-created* Idaho RECs, or enacted any legislation that automatically transfers RECs to a utility in *all* wholesale energy transactions. Instead, through Order No. 32697, the

Commission has unlawfully impaired IRP-based QFs' ability to possess and sell 50% of their RECs. Petitioners possessed the RECs associated with their QF output prior to Order No. 32697, but if Petitioners choose to renew their PPAs to sell at the IRP-based avoided cost rates they will no longer own 50% of their RECs. By its order, the Commission has now impaired Petitioners' right to transfer property for compensation.

Where the government requires an owner to suffer a permanent physical invasion of their property – however minor – it must provide just compensation. *See Loretto,* 458 U.S. at 438-39 (state law requiring landlords to permit cable companies to install cable facilities in apartment buildings effected a taking). A second categorical rule applies to regulations that completely deprive an owner of all economically beneficial use of her property. *Lucas,* 505 U.S., at 1019-1023; *Coeur d'Alene Garbage Service v. Coeur d'Alene,* 114 Idaho 588, 591, 759 P.2d 879, 881 (1988) (collecting Idaho cases and applying Idaho Constitution to find taking of garbage collection business by City action curtailing its business).[8] Since what the owner had was transferable value, "the question is, What has the owner lost? Not, What has the taker gained?" *Kimball Laundry Co. v. U.S.,* 338 U.S.1, 12-13 (1949); *see also Yancey v. U.S.,* 915 F.2d 1534, 1541–42 (Fed. Cir. 1990) (finding a compensable taking where "the Yanceys had no choice but to sell their birds for substantially less than their value").

Granting the utilities title to 50% of IRP-based QFs' RECs without providing any compensation to QFs constitutes a categorical taking. The Commission's order will leave the

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8 Even when the claimant still retains economic value of its property, just compensation may be required by weighing relevant factors set forth in *Penn Central Transp. Co. v. New York City,* 438 U.S. 104, 124 (1978). However, Order No. 32697 effects a direct appropriation of private property required for a categorical taking, thus precluding the need to engage in balancing the *Penn Central* factors for regulatory takings commonly used in zoning law. In any event, Order No. 32697 would also constitute a taking under application of the factors set forth in *Penn Central* because it provides no legitimate basis to impair Petitioners' property rights. *See Ruckelshaus,* 467 U.S. at 1005-1016; *Cienega Gardens v. U.S.,* 331 F.3d 1319, 1337-53 (Fed. Cir. 2003).

QFs with no choice but to cut a deal selling their RECs for "substantially less than their value" – in fact, 50% of the QFs' RECs must be sold for *no value*. *Yancey,* 915 F.2d at 1542. Because RECs are most valuable in forward strips, the order may also impair the value of the remaining 50% of the RECs QFs retain. The ostensible purpose for gifting RECs to the utilities is to protect utilities and their ratepayers from needing to pay the full avoided cost rates for energy and capacity. *See* Order No. 32697 at 46 ("From the utility's perspective, selling RECs produces revenue which directly offsets the utility's (and ratepayers) costs of purchasing power from QFs."). To authorize such a seizure under this reasoning would be a classic case of requiring an individual (QF) to forfeit its property (valuable environmental attributes) for public benefit (the ability to offset the cost of federally mandated payments to QFs at the full avoided costs) without any compensation. That is a taking.

The Commission's reliance on the Connecticut case is unavailing. *See Wheelabrator Lisbon, Inc. v. Connecticut Dept. of Pub. Util. Control*, 531 F.3d 183 (2nd Cir. 2008). There, the waste-to-energy QF at issue entered into a PURPA PPA in 1991. *Id.* at 186. "In 2002, the specific credits at issue . . . became marketable by the creation of a market for such credits pursuant to the laws of several states, including Connecticut." *Id.* Based on construction of the 1991 contract, the Connecticut Supreme Court concluded that the 1991 contract assigned REC ownership to the utility, and therefore the state commission's decision did not constitute a taking in violation of the state constitution. *Wheelabrator Lisbon, Inc. v. Dept. of Pub. Util. Control,* 931 A.2d 159, 176-77 (Conn. 2007). The federal district court likewise rejected a challenge under the takings clause on the ground that the RECs "were created after the parties entered into the [contract]." *Wheelabrator Lisbon, Inc. v. Connecticut Dept. of Pub. Util. Control*, 526

F.Supp.2d 295, 306 (D. Conn. 2006).[9] In stark contrast, Order No. 32697 expressly acknowledges that RECs exist today, and that Idaho avoided cost rates *do not compensate QFs for RECs*. Additionally, Petitioners (and many QFs in the state) have existing contracts which expressly state that Petitioners own the RECs. It follows that requiring QFs to gift 50% of the RECs to utilities as a precondition to exercise their right to sell QF energy and capacity at avoided cost rates is a taking of property without compensation.

5. Order No. 32697 violates the Dormant Commerce Clause of the U.S. Constitution by requiring in-state processing of 50% of Idaho IRP-based QFs' RECs – thus improperly impeding the flow of interstate commerce created by other states' policies.

The Commerce Clause of the United States Constitution provides that "Congress shall have Power . . . To regulate Commerce . . . among the States . . . ." U.S. Const., Art. I, § 8, cl. 3. The Dormant Commerce Clause, however, also imposes limitations on states in the absence of congressional action. "It is well settled that actions are within the domain of the Commerce Clause if they burden interstate commerce, *or impede its free flow*." *C&A Carbone, Inc. v. Town of Clarkstown, N.Y.*, 511 U.S. 383, 389 (1994) (emphasis added). "The central rationale for the rule against discrimination is to prohibit state or municipal laws whose object is local economic protectionism." *Id.* at 390. State laws requiring that goods be processed in-state prior to entering interstate commerce are per se invalid because such laws block the flow of interstate commerce at the state's borders. *See, e.g., id.* at 390 (striking down town ordinance requiring non-recyclable solid waste to be processed at designated facility within municipality before shipping); *S. Central Timber Devel., Inc. v. Wunnicke*, 467 U.S. 82, 100 (1984) (striking down

[9] The QF did not appeal to the Second Circuit with the taking argument, and therefore the Second Circuit never addressed the issue. *Wheelabrator Lisbon, Inc.*, 531 F.3d 183. *See also City of New Martinsville v. Pub. Serv. Commn. of W. Va.*, 229 W.Va. 353, 729 S.E.2d 188, 197 n.13 (W.Va. 2012) (concluding no taking occurred in Commission determination of ownership of RECs in contract pre-dating creation of RECs).

Alaska regulation that required all Alaska timber to be processed within the state before export); *New Hampshire v. New England Power*, 455 U.S. 331, 339 (1982) (holding that law restricting exports of hydropower violated commerce clause by hoarding resources for State's economic benefit).

In *C.A. Carbone, Inc.*, the Court specifically noted the ordinance requiring local processing of solid waste favored only a "single local proprietor," rather than a class of in-state processors, and held "this difference just ma[de] the protectionist effect of the ordinance more acute." *C&A Carbone, Inc.*, 511 U.S. at 392. "Discrimination against interstate commerce in favor of local business or investment is *per se* invalid, save in a narrow class of cases in which the municipality can demonstrate under rigorous scrutiny, that it has no other means to advance a legitimate local interest." *Id.* at 392. (distinguishing *Maine v. Taylor*, 477 U.S. 131 (1986), where the Court upheld a restriction on importation of baitfish because Maine had no other way to prevent spread of parasites and local economic interests were not the state's justification for the ban).

Here, the Commission's order directs the utilities to take title to an interstate commodity created by <u>other states'</u> RPS laws – RECs. In discussing RECs, FERC stated, "States, in creating RECs, have the power to determine who owns the REC in the initial instance, and how they may be sold or traded; it is not an issue controlled by PURPA." *Amer. Ref-Fuel Co.*, 105 FERC ¶ 61,004 at ¶ 23. Idaho does not have an RPS law that creates "Idaho RECs," and the Idaho legislature has stated no purpose whatsoever – let alone a legitimate purpose – to require QFs to give RECs to the utility. The Commission has deemed a commodity created by other states to be bundled to electrons for a small class of generators in Idaho – IRP-based QFs.

To do so – without requiring any compensation – is an act of local protectionism of Idaho's investor-owned electric utilities that would burden the interstate flow of goods and violate the Dormant Commerce Clause. *C&A Carbone, Inc.*, 511 U.S. at 390. The order unlawfully requires the RECs to be processed in-state and then resold out-of-state by the Commission's chosen proprietors. *See id.; S. Central Timber Devel., Inc.*, 467 U.S. at 100; *New Hampshire*, 455 U.S. at 339. Order No. 32697 effectively undermines the policies in neighboring states designed to provide an economic benefit to those who might expend time and effort to develop, own or upgrade a renewable energy project – here the IRP-based QF. This impermissibly burdens interstate commerce.

6. Order No. 32697 is unreasonable, erroneous, and arbitrary and capricious because it fails to provide a reasoned decision to depart from the Commission's prior determination refusing to grant Idaho Power a right of first refusal to buy a QF's RECs.

Order No. 32697 fails to dispense with past Commission orders on this topic, and is therefore unreasonable, erroneous, and arbitrary and capricious. It is a basic tenet of administrative law that an agency reversing its prior policy faces a heightened burden to reverse course. *See Motor Vehicle Mfrs. Ass'n of U.s., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 42 (1983) ("an agency changing its course by rescinding a rule is obligated to supply a reasoned analysis for the change beyond that which may be required when an agency does not act in the first instance."). Order No. 32697 completely overlooks that the Commission has previously declared that Idaho utilities may not condition the federally mandated purchase of QF power on a *right of first refusal to also buy the QF's RECs* and instead left parties to *negotiate the sale* of RECs to the utility.

Specifically, Idaho Power previously petitioned the Commission for an order declaring that QFs generating green tags must grant Idaho Power "a 'right of first refusal' to purchase those tags." Order No. 29480 at 4-5. Petitioners have provided this order as Attachment 4. PacifiCorp and Avista both intervened and requested that the Commission determine the utilities own the environmental attributes associated with QF generation. *Id.* at 5-8. The Commission found that Idaho Power's petition did "not present a justiciable controversy in Idaho and [wa]s not ripe for a declaratory judgment[.]" *Id.* at 16. The Commission observed the *Amer. Ref-Fuel, Co.* orders and noted that the State of Idaho does not have a green tag program or an RPS. It stated:

> While *this Commission will not permit [Idaho Power] in its contracting practice to condition QF contracts on inclusion of such a right-of-first refusal term*, neither do we preclude the parties from *voluntarily* negotiating the sale and purchase of such a green tag should it be perceived to have value. The price of same we find, however, is not a PURPA cost and is not recoverable as such by the Company.

Id. at 16-17 (emphasis added). The Commission's determination that a utility (Idaho Power) may not condition its federally mandated purchase of QF power on a *right of first refusal to also buy the QF's RECs* is the equivalent of an order that Idaho Power *does not own the RECs.* So is the suggestion that Idaho Power could negotiate to purchase those RECs if it wished.

Not surprisingly, Idaho Power thereafter filed for approval of a PURPA contract with J.R. Simplot Co. containing the published rates for a non-fueled project, wherein Idaho Power expressly waived any claim to ownership of environmental attributes. *See* Order No. 29577 at 2-3. The Commission stated, "The State of Idaho still has not created a green tag program, has not established a trading market for green tags, nor does it require a renewable portfolio standard." *Id.* at 5-6. It again stated that the QF and the utility were free to separately negotiate for the *sale* of environmental attributes, but that *the costs associated with the sale could not be recovered by the utility as a PURPA cost*. The Commission ruled, "[a]s qualified above, the Commission finds it reasonable to approve the submitted Agreement and further finds it reasonable to allow payments made under the Agreement as prudently incurred expenses for ratemaking purposes." *Id.* at 6. Thus, the Commission found it reasonable for the Utilities to waive ownership of environmental attributes because *the utility did not own the RECs*.

Despite the obvious intent behind these prior orders, in *Grand View Solar PV II v. Idaho Power Co.*, the Commission misconstrued its prior order to state that "we have held that the parties to a QF contract or PPA are *free to contract for the ownership of RECs*." Order No. 32580 at 10 (emphasis added). Order No. 32697 likewise relies on this faulty reasoning that its prior orders merely intended for QFs and utilities to negotiate the ownership of RECs. *See* Order No. 32697 at 47. This is perplexing. The prior order did not state parties could negotiate ownership of RECs. It stated Idaho Power could condition is purchase of QF energy and capacity on a right of first refusal to also separately purchase the QF's RECs. The Commission has re-written its prior orders. Doing so is unreasonable, arbitrary and capricious. It is also poor policy because parties rely upon the Commission's orders. Again, the Commission's determination that a utility (Idaho Power) may not condition its federally mandated purchase of QF power on a *right of first refusal to also buy the QF's RECs* is the equivalent of an order that Idaho Power *does not own the RECs*.

Petitioners' own contracts entered into contemporaneous to these prior Commission orders demonstrate the understanding at the time contemporaneous to the Commission's prior orders. As with the contract discussed above, the current Simplot contract entered into in 2006 contains a clause declaring Simplot the owner of the environmental attributes. *See* Attachment 2 at Art. 8. In approving the Potlatch contract (now Clearwater), the Commission stated, "The Commission finds that the $42.92/MWh levelized purchase price for the Potlatch base generation amount (62 aMW) is a reasonable approximation of Avista's avoided cost and was correctly calculated under the Commission approved IRP-based avoided cost methodology." Order No. 29418 at 9. The contract expressly disclaims Avista's right to the renewable attributes, and in fact Clearwater has been separately selling its renewable attributes to Avista under a separate agreement for additional compensation. *See* Attachment 3 at § 18. Order No. 32697 operates under the false assumption that nobody owned the RECs during this timeframe. It is simply not plausible.

Finally, Order No. 32697's reliance on more recent contracts where Idaho Power was able to coerce certain QFs into granting Idaho Power the right to 50% of their RECs is unpersuasive. *See* Order No. 32697 at 46. As Idaho Power itself freely admitted in this case, Idaho Power used a title-clouding clause in its draft QF contracts in order to coerce QFs into gifting RECs to Idaho Power. *See* Reading DI at Exhibit 506 (containing Idaho Power's discovery response on its title-clouding clause). Furthermore, despite the implicit assumption of Order No. 32697, not all of these QFs were IRP-based QFs. *See* Order No. 32451 (approving the Riverside Investments QF PPA for a project under 10 MW and ceding 50% of the RECs to Idaho Power). That these developers chose to give away 50% of their RECs to avoid litigating against Idaho Power does not undo the Commission's prior determinations on the topic. These contract approval dockets were not litigated and cannot establish a reasoned basis to depart from the prior determination in Order No. 29480. No reasoned basis exists for why utilities – which previously could not even insist on a right to buy the RECs – now simply own 50% of the RECs outright.

7. Order No. 32697 discourages QF development by undoing the financial benefits conferred on Idaho QFs by neighboring states' RPS laws.

At bottom, the reasoning and effect of Order No. 32697 blunts the financial benefit conferred on Idaho QFs by neighboring states' RPS laws – thus running afoul of the Commission's duty to *encourage* QF development. *See* 16 U.S.C. § 824a-3(a). The Commission went to great lengths in this proceeding to modify calculation of avoided cost rates to further the principle of ratepayer indifference to QFs. Even if the Commission adopts Petitioners' recommended revision to the IRP methodology set forth above, the avoided cost rates to emerge from this proceeding will be far lower for many QFs than they were prior to this proceeding. This demonstrates, yet again, that QFs receive compensation only for the projected value to the individual utility of the QFs' energy and capacity. The ratepayers and the utility should be indifferent. As such, PURPA merely provides QFs with access to sell at a rate calculated to provide ratepayer indifference.

RECs are different. RECs are a product of certain state's laws designed to provide an *additional* economic benefit to promote development of renewable energy projects in the region.[10] Idaho law does not even create any such RECs. The RECs exist because other states in the region have enacted laws allowing RECs to be produced by QF and non-QF generators in Idaho. The Commission's order effectively eliminates 50% of the economic benefit of the RECs for IRP-based QFs. The effect of the order is to go beyond the principle of ratepayer

[10] For example, Washington's statement of policy for its RPS states, "Increasing energy conservation and the use of appropriately sited renewable energy facilities builds on the strong foundation of low-cost renewable hydroelectric generation in Washington state and will promote energy independence in the state *and the Pacific Northwest region*." Rev. Code. Wash. 19.285.020 (emphasis added).

indifference and to actively discourage QF development by blunting the financial benefit neighboring states have chosen to confer on Idaho QFs and non-QFs. Aside from the legal arguments set forth above, the Commission should reconsider whether it wishes to discourage QF development by implementing a 50% reduction in value of a commodity designed to encourage renewable resources in the region.

IV. CONCLUSION

For the reasons set forth above, Petitioners respectfully request that the Commission reconsider and revise its determinations in Order No. 32697 as follows:

- Disavow use of the "singe-run" methodology for calculation of avoided cost rates for QFs in the IRP methodology, and instead require use of the IRP methodology proposed by Petitioners' witness, Dr. Don Reading; and
- Declare that QFs retain ownership of all environmental attributes, including RECs, when they sell QF energy and capacity to a utility at avoided cost rates calculated with the IRP Methodology.

Petitioners stand ready to present further briefing, oral argument, or any further technical testimony the Commission may request on the issues raised in this Petition.

DATED THIS 8th day of January 2013.

RICHARDSON AND O'LEARY, PLLC

By: [signature]
Peter J. Richardson (ISB No: 3195)
Gregory M. Adams (ISB No: 7454)

Attorneys for
J.R. Simplot Company, and
Clearwater Paper Corporation

CASE NO. GNR-E-11-03

PETITION FOR RECONSIDERATION
OF J.R. SIMPLOT COMPANY AND CLEARWATER PAPER CORPORATION

ATTACHMENT 1

Office of the Secretary
Service Date
May 20, 2010

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR APPROVAL OF AN AGREEMENT TO PURCHASE CAPACITY AND ENERGY FROM USG OREGON, LLC AND AUTHORIZE RECOVERY IN THE COMPANY'S POWER COST ADJUSTMENT	)	CASE NO. IPC-E-09-34 ORDER NO. 31087

On December 28, 2009, Idaho Power Company filed an Application requesting approval of a Purchase Power Agreement and an accounting order authorizing the Company to recover purchases of energy and associated costs from the USG Oregon, LLC, Neal Hot Springs Unit No. 1 geothermal generation facility. The Company seeks recovery of its costs and purchases in its annual Power Cost Adjustment (PCA).

The Application states that Idaho Power indicated in both its 2004 and 2006 Integrated Resource Plans (IRPs) that it intended to actively seek acquisition of geothermal generating resources. In 2006, the Company issued a request for proposal (RFP) to acquire geothermal resources and then entered into an agreement with U.S. Geothermal to purchase power from its Raft River No. 1 geothermal power plant. Idaho Power issued a new request for proposal in 2008 to acquire additional geothermal resources. The Company received three responses, two of which were withdrawn by the bidders, and the Company concluded that the third bid was too speculative and thus unacceptable. Application, p. 3. The Company's Application states that this experience with the unsuccessful RFP process demonstrates that "the competitive RFP process is not the optimal means to acquire geothermal resources." Application, pp. 3-4. Accordingly, the Company actively pursued discussions with developers of five different potential geothermal sites, including the Neal Hot Springs site. The Company believes the Neal Hot Springs development is advantageous for several reasons, including (1) substantial prior geotechnical exploration at the site, (2) its location in Idaho Power's service area and proximity to Treasure Valley load centers, (3) available transmission capacity, and (4) favorable energy pricing in comparison to other proposals. Application, p. 4.

On December 11, 2009, Idaho Power and USG Oregon, LLC entered into a Power Purchase Agreement providing for the Company's purchase of energy from the Neal Hot Springs

Unit No. 1 geothermal generation facility. USG Oregon, LLC is a subsidiary of U.S. Geothermal. The Neal Hot Springs project is located approximately 12 miles west northwest of Vale, Oregon. The project is expected to produce approximately 22 MW of power with an estimated online date late in 2012. The Purchase Agreement provides an initial term of 25 years with an option for Idaho Power to extend the term of the Agreement. The Agreement provides that Idaho Power will receive the rights to all environmental attributes and renewable energy credits now available or created during the term of the Agreement. The Agreement grants Idaho Power the first right-of-offer to participate in any future U.S. Geothermal resource development at the site or in close proximity to the site. Application, p. 5.

The energy price stated in the Agreement will be seasonally adjusted consistent with seasonality factors currently used in Idaho Power's PURPA agreements. The Company asserts that seasonal prices give the correct price signal by promoting production when the value of the energy to the Company is highest. Beginning in 2012, the flat energy price is \$96/MWh. The price escalates annually, resulting in a 25-year levelized contract price of approximately \$117.56/MWh. This compares to a levelized price for a 20-year PURPA contract of \$95.56/MWh. The Company asserts that, while the price of energy under this Agreement is higher than energy purchased under PURPA contracts, there are benefits to this Agreement that bring value to Idaho Power's customers that PURPA contracts do not. The Company identifies these benefits as (1) the Company's rights to any of the project's renewable energy credits, (2) the limited ability to curtail energy, (3) the right of first offer on ownership of other site development, (4) exploration, development and construction milestone requirements and associated damages, and (5) the right to extend the terms of the contract. The Application states that with the addition of a relatively minor system upgrade, sufficient firm transmission capacity is available for the full output of the project to be delivered to Idaho Power's load centers.

Because the Agreement is not a PURPA contract, the Company proposes that the cost of power purchased under the Agreement be recovered in its annual PCA in a manner similar to other non-qualified facility power purchase expenses. The Company requests that its Application be processed by Modified Procedure, that the Commission find that the Agreement is prudent for ratemaking purposes and that the Commission approve its request for recovery of the power purchase expense associated with the Agreement in the Company's power cost adjustment rate. On March 17, 2010, the Commission issued a Notice of Application and Notice of Modified

Procedure that provided notice of an opportunity to file written comments and reply comments on or before May 13, 2010. The only written comments received were filed by the Commission Staff.

Staff reviewed Idaho Power's process to obtain proposals for geothermal resources including the Company's effort to obtain the resources through the RFP process. The Company issued an RFP in 2006, and ultimately selected a proposal from U.S. Geothermal, Inc. to develop two 13 MW phases at the Raft River site near Malta, Idaho and two phases at Neal Hot Springs. Idaho Power issued a new RFP in January 2008 to acquire additional geothermal resources. The RFP specified bids for up to 100 MW with a target online date of June 2011, but also stated that the Company was willing to allow flexibility and possible delay in the project online date. The Company received three responses to the RFP, but ultimately two of the proposals were withdrawn by the bidders and the Company rejected the third. With this experience, the Company decided to directly discuss with developers the possibility of geothermal development, including possible development of the Neal Hot Springs site. Negotiations for generation at the Neal Hot Springs site began in April 2008.

Staff expressed two concerns with the negotiation process between Idaho Power and U.S. Geothermal. First, the prices in the Agreement submitted for Commission approval are higher than the prices offered by U.S. Geothermal in its RFP bid. Second, the scheduled operation date for the Neal Hot Springs project is much later than both the original 2010 online date originally proposed by U.S. Geothermal and the June 2011 date requested by Idaho Power in its 2006 RFP. The parties now estimate an online date of late 2012, but Staff noted that under the terms of the Agreement the project scheduled operation date could be as late as December 2017. Staff stated it is difficult to confirm that the pricing in the Agreement is favorable compared to other proposals because those proposals were withdrawn or rejected before serious negotiations began with U.S. Geothermal regarding the Neal Hot Springs site. Staff Comments, p. 7.

The energy prices contained in the Agreement begin in 2012 at $96 per MWh, and escalate during the 25 years of the term. Staff compared the contract rates with three other energy purchase rates to evaluate the reasonableness of the contract terms. Staff compared the energy prices to a 25-year PURPA contract for a facility smaller than 10 aMW, to a PURPA facility larger than 10 aMW, and to the cost of power that will be provided by Idaho Power's

Langley Gulch facility. The rates in the Neal Hot Springs Agreement are higher than all three of the other facilities. Staff Comments, pp. 7-9.

Despite identifying concerns with the Agreement, Staff recommended the Commission approve all of the Agreement's terms and conditions as submitted and find that all payments Idaho Power makes to USG Oregon, LLC for purchases of energy from the Neal Hot Springs Unit No. 1 generation facility will be allowed as prudently incurred expenses for ratemaking purposes. Additionally, Staff recommended the cost of power purchased under the Agreement be recovered in Idaho Power's annual PCA until the next general rate case, at which time the Company would be allowed to include costs as specified in the Agreement in base rates.

COMMISSION FINDINGS

Based on the record in this case, the Commission has determined to approve the power purchase agreement as filed with the Application. Although the energy costs for the Neal Hot Springs facility are higher than current PURPA rates, the Agreement provides benefits to Idaho Power as identified by the Application. For example, Idaho Power will receive ownership of all renewable energy credits associated with the facility, and this clearly will provide value to Idaho Power. Additional favorable contract terms include the Company's ability to curtail energy deliveries from the project, and the right of Idaho Power to purchase additional generation capacity if it is added in the future. The Agreement enables Idaho Power the first right to purchase the facility assets if the owner proposes to sell them during the term of the Agreement. The Agreement contains liquidated damages for construction delays and energy shortfall damages, contract terms that make it more favorable to the Company. Finally, Idaho Power has an option to extend the terms of the Agreement, although any extension requires re-negotiation of the terms and conditions. These contract terms provide value to Idaho Power in the project, and taken altogether, make the terms of the Agreement fair and reasonable. The Agreement also is significant in that it brings a unique generating facility into Idaho Power's mix of resources.

The Commission notes that this case presents a situation where the RFP process, the preferred method for obtaining competitive proposals for energy purchases, ultimately was not successful. Contract terms resulted from direct negotiations rather than through an RFP. In most circumstances where the RFP process is not successful, Idaho Power is not precluded from directly negotiating contract terms with a single provider. However, the Company always bears the burden, when seeking Commission approval of a purchase agreement, of demonstrating its terms are fair, just and reasonable.

The Commission finds the terms of the Purchase Power Agreement between Idaho Power and USG Oregon, LLC, Neal Hot Springs Unit No. 1 geothermal generation facility to be fair, just and reasonable. Purchases of energy from the Neal Hot Springs Unit No. 1 generation facility will be allowed as prudently incurred expenses for ratemaking purposes, and may be recovered in Idaho Power's annual PCA until the Company's next general rate case. Idaho Power is directed to provide copies of progress reports that are required under the Agreement to Staff. If the contract terms are amended for any reason, the Company is required to submit the new terms to the Commission for review and approval.

ORDER

IT IS HEREBY ORDERED that the Application of Idaho Power Company for approval of the purchase of energy from USG Oregon, LLC, Neal Hot Springs Unit No. 1 geothermal generation facility is approved. Purchases of energy from the Neal Hot Springs Unit No. 1 generation facility will be allowed as prudently incurred expenses for ratemaking purposes, and may be recovered in Idaho Power's annual PCA until the Company's next general rate case.

THIS IS A FINAL ORDER. Any person interested in this Order (or in issues finally decided by this Order) or in interlocutory Orders previously issued in this case may petition for reconsideration within twenty-one (21) days of the service date of this Order with regard to any matter decided in this Order or in interlocutory Orders previously issued in this case. Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. See *Idaho Code* § 61-626.

DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 20th day of May 2010.

JIM D. KEMPTON, PRESIDENT

MARSHA H. SMITH, COMMISSIONER

MACK A. REDFORD, COMMISSIONER

ATTEST:

Jean D. Jewell
Commission Secretary

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UTILITIES COMMISSION

BARTON L. KLINE
Lead Counsel
bkline@idahopower.com

December 28, 2009

VIA HAND DELIVERY

Jean D. Jewell, Secretary
Idaho Public Utilities Commission
472 West Washington Street
P.O. Box 83720
Boise, Idaho 83720-0074

Re: Case No. IPC-E-09-34
IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AN ACCOUNTING ORDER AUTHORIZING THE INCLUSION OF POWER SUPPLY EXPENSES ASSOCIATED WITH THE PURCHASE OF CAPACITY AND ENERGY FROM USG OREGON LLC IN THE COMPANY'S POWER COST ADJUSTMENT

Dear Ms. Jewell:

Enclosed please find for filing an original and seven (7) copies of Idaho Power Company's Application in the above matter.

Very truly yours,

Barton L. Kline

BLK:csb
Enclosures

P.O. Box 70 (83707)
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Boise, ID 83702

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Attorneys for Idaho Power Company

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UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AN ACCOUNTING ORDER AUTHORIZING THE INCLUSION OF POWER SUPPLY EXPENSES ASSOCIATED WITH THE PURCHASE OF CAPACITY AND ENERGY FROM USG OREGON LLC IN THE COMPANY'S POWER COST ADJUSTMENT.	CASE NO. IPC-E-09-34 APPLICATION

Idaho Power Company ("Idaho Power" or the "Company"), in accordance with Idaho Code § 61-503 and RP 52, hereby respectfully applies to the Idaho Public Utilities Commission ("IPUC" or the "Commission") for an accounting order authorizing Idaho Power to include the expenses associated with the purchase of energy from the USG Oregon LLC, Neal Hot Springs Unit #1 geothermal generation facility ("Project") in the Company's Power Cost Adjustment. In support of this Application Idaho Power represents as follows:

I. BACKGROUND

1. Over the past several years, Idaho Power has made a concerted effort to acquire cost-effective energy from geothermal generating resources for its resource portfolio. In its 2004 and 2006 Integrated Resource Plans ("IRPs"), the Company discussed why it is strongly supportive of the acquisition of energy from geothermal generating resources. First, geothermal generation utilizes a renewable resource, geothermally heated fluid, which decouples the project's variable operating costs from the volatility associated with the cost of fossil fuels. Geothermal generation, except for occasional planned and forced outages, is unique in comparison to other renewable resources (i.e., wind, solar, run-of-river hydro, etc.), which are more intermittent in their availability. Geothermal generation is essentially available 24/7 throughout the year and therefore can be considered to be a baseload resource. Second, numerous studies and tests indicate that it is likely that there are significant sources of geothermally heated hot water underlying Idaho Power's service area. Development of these geothermal resources will add economic value in local communities in the Company's service territory and will make efficient use of limited transmission capacity. Third, under various Renewable Portfolio Standards, geothermal resources qualify for renewable energy credits that can provide independent financial and environmental benefits to Idaho Power and its customers. Fourth, the inclusion of geothermal resources in the Company's resource portfolio provides diversity and reduced exposure to fuel cost fluctuations. Finally, due principally to very aggressive renewable portfolio standards, particularly in California, a number of utilities are actively seeking to acquire geothermal resources throughout the entire western United States. In short, geothermal generation

resources have the potential to provide a desirable, long-term, and economically stable generating resource for Idaho Power and there is some urgency to move forward to develop these desirable local resources.

2. Idaho Power disclosed its intention to actively seek to acquire geothermal generating resources in both its 2004 and 2006 IRPs. In 2006, Idaho Power issued a Request for Proposals ("RFP") to acquire geothermal resources. The 13 MW Raft River Geothermal Power Plant Unit #1, developed by a subsidiary of U.S. Geothermal, was selected as one of the successful proposals. The Raft River #1 plant began delivering energy to Idaho Power in April 2008 under a power purchase agreement developed as a result of the 2006 RFP process. U.S. Geothermal included additional geothermal projects in its successful 2006 bid, including additional generation at Raft River and a new project at Neal Hot Springs. However after further review of escalating construction costs, U.S. Geothermal concluded that its fixed-price bid was not viable and withdrew its offer to sell power from the Neal Hot Springs site as submitted.

3. Consistent with its continuing desire to include geothermal generation in its resource portfolio, Idaho Power issued a new RFP in 2008 to acquire additional geothermal resources. This 2008 RFP received three responses, two of which were shortly withdrawn by the bidders prior to Idaho Power fully evaluating the bids. Idaho Power concluded that the third bid was too speculative and therefore unacceptable.

4. In reviewing the disappointing results of the 2006 and 2008 geothermal RFPs both internally and with geothermal industry experts, it has become apparent to Idaho Power that due to the substantial uncertainties inherent in the exploration and

development processes required for geothermal projects, the competitive RFP process is not the optimal means to acquire geothermal resources.

5. Based on its belief that a non-RFP driven resource acquisition process for geothermal resources is more likely to be successful, Idaho Power has actively pursued development discussions with the developers of approximately five different potential geothermal sites. These sites had been identified in previous RFPs or brought to the Company's attention as a result of previous proposals received directly from developers. The Project identified in this Application became the front-runner in the non-RFP procurement process for several reasons, including: (1) substantial prior geotechnical exploration of the potential resource site, (2) its location in Idaho Power's service area and proximity to Treasure Valley load centers, (3) available transmission capacity, and (4) favorable energy pricing in comparison to other proposals. Idaho Power is continuing discussions with the other potential geothermal projects and, consistent with the action plans in its accepted IRPs, may, in the future, present to the Commission power purchase agreements for additional geothermal resources Idaho Power determines to be prudent choices to fulfill Idaho Power identified energy needs.

II. GENERAL DESCRIPTION OF TERMS AND CONDITIONS IN THE POWER PURCHASE AGREEMENT FOR THE NEAL HOT SPRINGS UNIT #1 PROJECT

6. On December 11, 2009, Idaho Power and USG Oregon LLC entered into a Power Purchase Agreement ("Agreement") for the purchase of energy from the Neal Hot Springs Unit #1 geothermal electrical generation facility. USG Oregon LLC is a subsidiary of U.S. Geothermal, a Boise-based geothermal developer. The Project will be located approximately 12 miles WNW of Vale, Oregon, just west of the Bully Creek

Reservoir. The expected MW output from the Project will be approximately 22 MW, with an estimated on-line date of late 2012 (the Agreement requires an on-line date no later than 2016) and with an initial term of 25 years with an option for Idaho Power to extend the term of the Agreement. A copy of the Agreement is enclosed as Attachment No. 1.

7. Under the Agreement, Idaho Power will receive, as a part of the purchase price, the rights to all Environmental Attributes and Renewable Energy Credits ("RECs") as currently known and any additional Environmental Attributes and Renewable Energy Credits created during the term of the Agreement.

8. The Agreement requires the Project to maintain a 90 percent capacity factor, with applicable annual energy output guarantees. Various development milestones have been established within the Agreement. Failure to meet these development milestones or annual output guarantees will result in damages being calculated and will require the Project to post liquid security. The Project is required to provide energy delivery forecasting to Idaho Power. The Agreement also allows Idaho Power to curtail energy deliveries to Idaho Power in an amount up to 1,620 MWh per contract year at no cost to Idaho Power. This curtailment right will allow the Company some flexibility, albeit limited, to dispatch the Project to benefit customers.

9. Delay damages and other liquidated damages are applicable based upon the Projects compliance with various exploration, development, and construction milestones, as well as its ongoing performance.

10. The Agreement grants Idaho Power the first right-of-offer to participate in any future U.S. Geothermal resource development at this geothermal site or in close proximately to the site and in any future ownership restructuring of the planned Project.

11. The energy price within the Agreement will be seasonally adjusted consistent with seasonality factors currently being used in Idaho Power's PURPA agreements. Using seasonality factors to adjust prices provides for reduced energy prices in months of historically low market energy values, with increased energy prices in months when Idaho Power experiences its peak energy needs. Seasonal prices give the correct price signal by incenting production when the value of the energy to the Company is the highest. Beginning in 2012, the flat energy price (energy price to which seasonality is then applied) is $96.00/MWh. An annual price escalation that varies from 6 percent in the initial years to 1.33 percent in the later years of the Agreement was used to create the fixed monthly price schedule shown in Appendix A of the Agreement. Applying levelized energy pricing models to this fixed set of prices results in an approximate 25-year levelized contract price of $117.56.

12. For comparison purposes, PURPA contracts are currently only available for a 20-year term. The levelized price for a 20-year PURPA contract, with first energy deliveries in 2012 is $95.56/MWh (IPUC Order No. 30744). The calculated levelized contract price for energy provided under this Agreement for a 20-year term would be approximately $115.28/MWh. IPUC Order No. 30744 establishes PURPA non-levelized contract price for energy received in 2012 to be $80.05/MWh, which escalates to $138.93/MWh in calendar year 2034 (2034 is the last year currently priced in IPUC Order No. 30744). The energy price for 2012 in the Agreement is $96.00/MWh and the price escalates to $140.82/MWh in 2034. While the price of energy under the Agreement is higher than energy purchased under PURPA contracts, there are aspects of the Agreement that bring value to Idaho Power's customers that PURPA contracts do

not. For example, typical PURPA agreements currently do not provide Idaho Power rights to any of the project's RECs. To obtain the RECs for a PURPA project, Idaho Power must incur additional costs to purchase those credits from the developer in a separate transaction. PURPA agreements offer no energy curtailment rights, no operational financial security requirements, no rights of first offer on ownership or other site development, no exploration, development or construction milestone requirements and associated damages, and no rights for extension of the contract term.

13. USG Oregon LLC has submitted a request and completed a Large Generation Interconnection Agreement for this Project. The Project will pay all interconnection costs associated with this Project and the schedule for completion of installation and construction of all required interconnection equipment is consistent with the Projects expected energy delivery dates. With the addition of one relatively minor system upgrade, sufficient firm transmission capacity is available for the full output of the Project to be delivered to Idaho Power's load centers. The Project will advance the cost of the upgrade and receive credit for its advanced funds based on its capacity and the OATT rate.

14. Section 1.8, Articles 27 and 28 of the Agreement provides that the Agreement will not become effective until the Commission has approved all of the Agreement's terms and conditions and declared that all payments Idaho Power makes under this Agreement will be allowed as prudently incurred expenses for ratemaking purposes.

III. ACCOUNTING TREATMENT

15. Idaho Power intends to include the expenses associated with the purchases from the Project in FERC Account 555. The Agreement is not a PURPA agreement and therefore the Company proposes that the cost of power purchased under the Agreement be recovered in the PCA in a manner similar to other non-QF power purchase expenses, with 95 percent of variations captured through the Company's PCA mechanism until the next general rate case, at which time the Company will be allowed to include the costs of the Agreement in base rates.

IV. MODIFIED PROCEDURE

16. Idaho Power believes that a hearing is not necessary to consider the issues presented herein and respectfully requests that this Application be processed under Modified Procedure, i.e., by written submissions rather than by hearing. RP 201, *et seq*. If, however, the Commission determines that a technical hearing is required, the Company stands ready to present its testimony and support the Application in such hearing.

V. COMMUNCIATIONS AND SERVICE OF PLEADINGS

17. Communications and service of pleadings, exhibits, orders, and other documents relating to this proceeding should be sent to the following:

Barton L. Kline, Lead Counsel
Donovan E. Walker, Senior Counsel
Idaho Power Company
P.O. Box 70
Boise, Idaho 83707
bkline@idahopower.com
dwalker@idahopower.com

Randy C. Allphin
Contract Administrator
Idaho Power Company
P.O. Box 70
Boise, Idaho 83707
rallphin@idahopower.com

VI. <u>REQUEST FOR RELIEF</u>

18. Idaho Power Company respectfully requests that the Commission issue an Order: (1) Authorizing that this matter be processed by Modified Procedure; and (2) finding that the Agreement is prudent for ratemaking purposes; and (3) approving Idaho Power's requested accounting treatment for inclusion of the power purchase expense associated with the Agreement in the Company's Power Cost Adjustment rate.

Respectfully submitted this 28th day of December 2009.

BARTON L. KLINE
Attorney for Idaho Power Company

CERTIFICATE OF MAILING

I HEREBY CERTIFY that on the 28th day of December 2009 I served a true and correct copy of the within and foregoing APPLICATION upon the following named parties by the method indicated below, and addressed to the following:

USG Oregon LLC Dan Kunz USG Oregon LLC 1505 Tyrell Lane Boise, Idaho 83706	____ Hand Delivered _X_ U.S. Mail ____ Overnight Mail ____ FAX ____ Email

Barton L. Kline

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-09-34

IDAHO POWER COMPANY

ATTACHMENT NO. 1

POWER PURCHASE AGREEMENT
BETWEEN
USG OREGON LLC
AND
IDAHO POWER COMPANY

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POWER PURCHASE AGREEMENT

BETWEEN

USG OREGON LLC

AND

IDAHO POWER COMPANY

This Power Purchase Agreement ("Agreement") is entered into this 11th day of December, 2009, by and between USG OREGON LLC, a Delaware limited liability company with a principal place of business at 1505 Tyrell Lane, Boise, ID 83706 ("Seller"), and IDAHO POWER COMPANY, an Idaho corporation with a principal place of business at 1221 W. Idaho Street, Boise, ID 83702 ("Buyer"). Seller and Buyer may be referred to individually as "Party," or jointly as "Parties."

Recitals

A. Seller desires to develop, construct, own and operate a geothermal electric generating facility known as the Neal Hot Springs Unit #1 with an estimated average annual net output of no less than 14,000 kW and no greater than 25,000 kW. At the time of signing this Agreement the expected estimated average annual net output is 22,000 kW. This estimated average annual net output will be precisely established as specified in Article 3.

B. Seller desires to deliver, and sell the full electrical energy output from this facility to the Buyer along with all environmental benefits associated with the electrical energy output for all calendar months of each year for the full term of this Agreement.

C. Seller and Buyer wish to enter into this Agreement in order to set forth the terms and conditions under which Seller will sell and Buyer will purchase energy from the Seller's Facility.

NOW, THEREFORE, in consideration of the mutual covenants contained in this Agreement, the sufficiency and adequacy of which are hereby acknowledged by each Party, the Parties agree to the following:

ARTICLE 1
DEFINITIONS

1.1 "Affiliate" means any other person or entity that controls, is under the control of, or is under common control with, the named person or entity. For purposes of this definition, the term "control" (including the terms "controls," "under the control of," and "under common control with") means the possession, directly or indirectly, of the power to direct or cause the direction of the management or the policies of a person or entity, whether through ownership interest, by contract or otherwise.

1.2 "Annual Allowed Energy Reduction" means 1,620 MWh for each Contract Year.

1.3 "Annual Capacity Factor" means 90%.

1.4 "Annual Guaranteed Output" means the Annual Output Forecast as defined in Section 8.5 multiplied by the Annual Capacity Factor.

1.5 "Bankrupt" means with respect to any entity, such entity (1) files a petition or otherwise commences, authorizes or acquiesces in the commencement of a proceeding or cause of action under any bankruptcy, insolvency, reorganization or similar law, or has any such petition filed or commenced against it, (2) makes an assignment or any general arrangement for the benefit of creditors, (3) otherwise becomes bankrupt or insolvent (however evidenced), (4) has a liquidator, administrator, receiver, trustee, conservator or similar official appointed with respect to it or any substantial portion of its property or assets, or (5) is generally unable to pay its debts as they fall due. The term "Bankruptcy" shall have a corollary meaning when used herein.

1.6 "Business Day" means any calendar day that is not a Saturday, a Sunday, or a NERC-recognized holiday.

1.7 "Commission" means the Idaho Public Utilities Commission or its successor.

1.8 "Commission Approval" means an order issued by the Commission approving this Agreement and finding the Contract Price to be reasonable and that all payments to be made to Seller under this Agreement shall be allowed as prudently incurred expenses of Buyer for ratemaking purposes, without condition(s) or modification(s) other than condition(s) or modification(s) accepted in writing by the Party or Parties adversely affected by such condition(s) or modification(s).

1.9 "Contract Price" means the price for all Net Energy that has been agreed to by the Parties in this Agreement and referenced in Appendix A.

1.10 "Contract Year" means the period commencing March 1st of the first calendar year after the establishment of the Operation Date ending one (1) year later, and each one year period thereafter beginning on March 1.

1.11 "Credit Rating" means (1) with respect to any entity other than a financial institution, the (a) current ratings issued or maintained by S&P's or Moody's with respect to such entity's long-term senior, unsecured, unsubordinated debt obligations (not supported by third-party credit enhancements) or (b) corporate credit rating or long-term issuer rating issued or maintained with respect to such entity by S&P's or Moody's, or (2) if such entity is a financial institution, the ratings issued or maintained by S&P's or Moody's with respect to such entity's long-term, unsecured, unsubordinated deposits.

1.12 "Delay Energy Quantity" means 3,000 kW less any portion of the capacity rating (kW) of the Facility that has met the Operation Date requirements specified in Section 5.4 multiplied by the hours beginning with the 744th hour past midnight of the Scheduled Operation Date to midnight of the day preceding the Operation Date, not to exceed, 2,160 total hours.

1.13 "Delay Liquidated Damages" means the Delay Energy Quantity multiplied by the Delay Price.

1.14 "Delay Price" means 85% of the applicable month's Market Energy Cost less the applicable month's Contract Price as specified in Appendix A. If this calculation results in a value less than zero (0) then the result will be zero (0).

1.15 "Designated Dispatch Facility" means Buyer's generation dispatch group or any subsequent group designated by Buyer.

1.16 "Effective Date" means the date first written above.

1.17 "Emergency" means an emergency condition as defined under the Interconnection Agreement or the applicable OATT.

1.18 "Environmental Attributes" means the aggregate amount of environmental air quality credits, off-sets, or other benefits related to the Net Energy and Test Energy produced by the Facility that reduces, displaces or off-sets emissions resulting from fuel combustion at another location pursuant to any federal, state or local legislation or regulation, and the aggregate amount of credits, offsets or other benefits related to Buyer's current marketing program, any successor green pricing program, or other environmental or renewable energy credit trading program derived from the use, purchase or distribution of Net Energy from the Facility or any similar program pursuant to any federal, state or local legislation or regulation. The Environmental Attributes include, but are not limited to, green tags, green certificates, renewable energy credits (REC's) and tradable renewable certificates directly associated with the Net Energy produced at this Facility. One REC is associated with the generation and delivery of one thousand (1,000) kWh of Net Energy. Notwithstanding any other provision of this Agreement, Environmental Attributes *do not include*: (1) the PTC's, (2) any investment tax credits, and any other tax credits, deductions, exemptions, or other tax benefits associated with the Facility, and (3) any state, federal, local or private cash payments, exemptions, refunds or grants relating in any way to the Facility, construction of the Facility or output of the Facility, including the production of Test Energy, Station Use, or Net Energy.

1.19 "Facility" means the electric generation facility commonly known as Seller's Neal Hot Springs Unit #1 geothermal power plant, as described in more detail in Appendix B, which includes all of the equipment required to enable this power plant to produce and deliver the electric energy as specified within this Agreement to the Buyer. This equipment shall include, but not be limited to, the electrical interconnection equipment, generator, turbine, heat exchanger, and cooling tower(s). The geothermal fluid extraction wells, geothermal fluid injection wells, geothermal fluid transportation systems from the various wells to the generation unit are included in the Facility to the extent that they are used in the production of energy from the Facility.

1.20 "Facility Assets" shall have the meaning given to that term in Section 29.7.1.

1.21 "Facility Lender" means, collectively, any lender(s) providing any Project Financing and any guarantors of such lenders and successor(s) or assigns thereto that Seller identifies in Article 32.

1.22 "Financing Documents" means the loan and credit agreements, notes, bonds, indentures, security agreements, lease financing agreements, mortgages, deeds of trust, and other documents relating to any Project Financing for the Facility, and any and all amendments, modifications, or supplements to the foregoing that may be entered into from time to time at the discretion of Seller in connection with any Project Financing of the Facility, or of the Facility in combination with other assets of the Seller.

1.23 "First Energy Date" means the day commencing at 00:01 hours, Mountain Time, following the day that the conditions in Section 4.1 have been satisfied.

1.24 "Forced Outage" means a Facility condition that requires a sudden or mandatory unplanned curtailment of the Net Energy deliveries from the Facility that (1) is due to equipment failure or unplanned shutdown which was not caused by an event of *force majeure* or by neglect, disrepair or lack of adequate preventative maintenance of the Seller's Facility or (2) is required to allow unplanned repair or maintenance to prevent equipment failure.

1.25 "Good Utility Practice(s)" means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result of the lowest reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice(s) is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region and consistently adhered to.

1.26 "Guaranty" means an instrument or agreement pursuant to which a guarantor guarantees the performance of the obligations of an obligor, which instrument or agreement is substantially in the form set forth as Appendix C.

1.27 "Guaranty Default" means with respect to a Guaranty or the guarantor thereunder, the occurrence of any of the following events: (1) any representation or warranty made or deemed to be made or repeated by such guarantor in connection with such Guaranty shall be false or misleading in any material respect when made or when deemed made or repeated; (2) such guarantor fails to pay, when due, any amount required pursuant to such Guaranty; (3) the failure of such guarantor to comply with or timely perform any other material covenant or obligation set forth in such Guaranty if such failure is not capable of remedy or shall not be remedied in accordance with the terms and conditions of such Guaranty; (4) such Guaranty shall expire or terminate, or shall fail or cease to be in full force and effect and enforceable in accordance with its terms against such guarantor, prior to the satisfaction of all obligations of the obligor under this Agreement, in any such case without replacement; (5) such guarantor shall repudiate, disaffirm, disclaim, or reject, in whole or in part, or challenge the validity of, its Guaranty, or (6) such guarantor becomes Bankrupt; provided, however, that no Guaranty Default shall occur or be continuing in any event with respect to a Guaranty after the time such Guaranty is required to be canceled or returned to a Party in accordance with the terms of this Agreement.

1.28 "Initial Term" has the meaning given to that term in Section 5.1.1.

1.29 "Interconnection Agreement" means the agreement between the Interconnection Provider and the Seller that enables the Seller's energy to be delivered and integrated into the Interconnection Provider's electrical system.

1.30 "Interconnection Facilities" means all equipment required to be installed to interconnect and deliver energy from the Facility to the Interconnection Provider's system including, but not limited to, connection, switching, metering, relaying, communications and safety equipment.

1.31 "Interconnection Provider" means that portion of Idaho Power Company, or its successor, that is responsible for the interconnections and operations of the Idaho Power Company distribution and transmission system as specified in the Idaho Power Company OATT.

1.32 "Interest Rate" means (1) for purposes of identifying the Interest Rate to be paid on cash collateral, an annual interest rate equal to the overnight federal funds rates, or (2) for purposes of identifying the Interest Rate to be paid in an event of default, an annual interest rate equal to one hundred percent (100%) of the LIBOR three (3) month rate plus two hundred (200) basis points. The designated Interest Rate shall be the rate published on the date of the invoice, or other notice, in *The Wall Street Journal* (or, if *The Wall Street Journal* is not published on that day, the next succeeding date of publication); *provided, however,* that the annual interest rate used as the Interest Rate shall not exceed the maximum rate permitted by law.

1.33 "Investor" means any investor(s) (including any transferees of such investors) that acquire a direct or indirect interest in Seller that Seller identifies in Article 32.

1.34 "Market Energy Cost" means the monthly weighted average of the daily on-peak and off-peak Dow Jones Mid-Columbia Index (Dow Jones Mid-C Index) prices for non-firm energy. If the Dow Jones Mid-C Index price is discontinued by the reporting agency, both Parties will mutually agree upon a replacement index similar to the Dow Jones Mid-C Index. The selected replacement index will be consistent with other similar agreements and a commonly used index by the electrical industry.

1.35 "Market Energy Price" means ninety percent (90%) of the Market Energy Cost.

1.36 "Material Adverse Change" means, with respect to Seller's Guarantor, the Guarantor's non-credit enhanced unsecured debt has (a) a Credit Rating below BBB- by S&P or below Baa3 by Moody's, or (b) a Credit Rating of BBB– by S&P accompanied by a negative watch or Baa3 by Moody's accompanied by a negative watch, or (c) both ratings are withdrawn or terminated on a voluntary basis by the rating agencies. If S&P changes its rating system during the Term, "BBB–" shall be replaced by S&P's lowest investment grade rating under the new rating system; likewise, if Moody's changes its rating system during the Term, "Baa3" shall be replaced by Moody's lowest investment grade rating under the new rating system.

1.37 "Material Breach" means a default or Event of Default (Article 25) subject to Section 25.3.

1.38 "Maximum Capacity" shall not exceed 30,000 kW without prior mutual consent by both Parties and will be precisely established as specified in Section 3.2.2.

1.39 "Metering and Telemetry Equipment" means all equipment specified in the Interconnection Agreement, this Agreement, and any additional equipment specified in Appendix B required to measure, record and telemeter power flows between the Facility and the Interconnection Provider's electrical system.

1.40 "Metering Point" means the point where the Seller's energy is measured by the Interconnection Provider's Metering Equipment.

1.41 "Moody's" means Moody's Investor Services, Inc. or its successor.

1.42 "NERC" means the North American Electric Reliability Council or its successor.

1.43 "Net Energy", expressed in (kWh), means all of the electric energy produced by the Facility, less Station Use, and delivered to and measured at the Metering Point that is (1) after an Operation Date has been established (2) is delivered by the Seller to the Metering Point and accepted by the Buyer at the Metering Point and (3) not exceeding the Maximum Capacity. Net Energy does not include Test Energy.

1.44 "Net Energy Shortfall" means as calculated in Section 8.5.5 and subject to Net Energy Shortfall Damages.

1.45 "Net Energy Shortfall Price" means the price used to calculate the Net Energy Shortfall Damages as specified in Appendix D.

1.46 "Net Energy Shortfall Damages" means any remaining Net Energy Shortfall after the provisions of Section 8.5.5.2 have been applied, multiplied by the Net Energy Shortfall Price applicable to the actual period when the Net Energy Shortfall occurred.

1.47 "OATT" means the Open Access Transmission Tariff applicable to the Interconnection Provider's system or the Buyer's transmission system.

1.48 "Operation Date" means the day commencing at 00:01 hours, Mountain Time, following the day that all conditions of Section 5.4 have been satisfied.

1.49 "Performance Assurance" means collateral in the form of either a Guaranty, cash, letter(s) of credit, or other security acceptable to Buyer, as described in Article 15.

1.50 "Point of Delivery" means the point where the Transmission Tap intersects the Interconnection Provider's Vale-Unity transmission line.

1.51 "Project Financing" means debt with respect to which the Facility Lender(s) are granted security interests in the Facility, as well in such other of Seller's assets, and in such revenues generated therefrom, as are specified in the Financing Documents.

1.52 "Project Milestone" means a defined date by which time the Seller shall have accomplished a particular activity, as defined in Appendix H.

1.53 "PTC's" means Production Tax Credits applicable to electricity produced from certain renewable resources pursuant to 26 U.S.C. § 45, or replacement or substitute tax benefits based on energy production from the Facility.

1.54 "PTC Value" means if the Seller elects to receive PTCs for this Facility, an amount equal to: (a) the PTC's to which Seller would have been entitled with respect to renewable energy it is unable to deliver because of a Buyer Event of Default; plus (b) a "gross up" amount to take into account the federal, state and local income tax to Seller on such payments in lieu of PTC's, so that the net amount retained by Seller, after payment of federal, state and local income taxes, is equal to the amount set forth in clause (a) of this definition. For purposes of determining the foregoing, Seller shall deliver a certificate from an officer of Seller stating the corporate income tax rates (federal, state or local, as applicable) that are in effect for the Seller during the tax year in which the receipt of such PTC Value is taxed, and such income tax rates shall be used in the calculation of the PTC Value. If the Seller does not elect to receive PTC's for this Facility, the PTC Value shall be zero (0).

1.55 "Scheduled First Energy Date" means the date that is thirty (30) months from the date on which the Seller issues the notice to proceed for the power plant construction as described in the fourth Project Milestone of Appendix H.

1.56 "Scheduled Maintenance" means as defined in Section 12.2.

1.57 "Scheduled Operation Date" means six (6) months after the Scheduled First Energy Date.

1.58 "Scheduled Outage" means the pre-scheduled kWh curtailment associated with the Scheduled Maintenance.

1.59 "Seller's Guarantor" means the entity providing the Guaranty or a successor or assignee thereof that is not experiencing a Material Adverse Change.

1.60 "Site" means the parcel of real property on which the Facility will be constructed and located, including any easements, right-of-ways, surface use agreements, and other interests or rights in real estate reasonably necessary for the construction, operation and maintenance of the Facility.

1.61 "Station Use" means electric energy produced by the Facility that is used to operate equipment that is auxiliary or otherwise related to the production of electricity by the Facility, including geothermal fluid pumps.

1.62 "S&P" means Standard & Poor's, a division of McGraw-Hill Companies Inc. or its successor.

1.63 "Term" means the period of time during which this Agreement shall remain in full force and effect, including the Initial Term and any extension of the Term as provided in Article 5.

1.64 "Test Energy" (expressed in kWh), means all of the electric energy produced by the Facility, less Station Use, and delivered to and measured at the Metering Point, that is (1) <u>prior</u> to an Operation Date being established and (2) delivered by the Seller to the Metering Point and accepted by the Buyer at the Metering Point and (3) not exceeding the Maximum Capacity.

1.65 "Total Annual Facility Net Energy" means the sum of twelve (12) months of actual Net Energy beginning with March 1st of each calendar year.

1.66 "Transmission Tap" means the approximate eleven (11) mile transmission line connecting the Facility to the Point of Delivery.

1.67 "WECC" means the Western Electricity Coordinating Council or its successor.

1.68 "WREGIS" means the Western Renewable Electricity Generation Information System which is an independent, renewable energy tracking system for the region covered by the Western Electricity Coordinating Council (WECC).

ARTICLE 2
RULES OF CONSTRUCTION

2.1 General. The defined terms listed in Article 1 (as indicated by initial capitalization) shall have the meanings set forth in Article 1 whenever the terms appear in this Agreement and attached Appendices, whether in the singular or the plural or in the present or past tense. Other terms used in this Agreement but not listed in Article 1 shall have meanings as otherwise defined within this Agreement or as commonly used in the English language and, where applicable, in Good Utility Practice(s). Words not otherwise defined in this Agreement that have well-known and generally accepted technical or trade meanings are used in accordance with such recognized meanings. In addition, the following rules of interpretation shall apply:

2.1.1 The masculine shall include the feminine and neuter.

2.1.2 References to "Articles," "Sections," or "Appendices" shall be to articles, sections or appendices of this Agreement.

2.1.3 The Appendices attached to this Agreement are incorporated in and are intended to be a part of this Agreement.

2.1.4 This Agreement was negotiated and prepared by both Parties with the advice and participation of counsel. The Parties have agreed to the wording of this Agreement, and none of the provisions of this Agreement shall be construed against one Party on the grounds that such Party is the author of this Agreement or any part of this Agreement.

2.1.5 The Parties shall act reasonably and in accordance with the principles of good faith and fair dealing in the performance of this Agreement. Unless expressly provided otherwise in this Agreement, (i) where the Agreement requires consent, approval, or a similar action by a Party, such consent, approval or other action shall not be unreasonably withheld, conditioned or delayed, and (ii) where the Agreement gives a Party a right to determine, require, specify or take similar action with respect to a matter, such determination, requirement, specification or similar action shall be reasonable.

2.2 Interpretation of Interconnection Agreement and Interconnection Provider documentation. The Parties recognize that the Seller has entered into a separate Interconnection Agreement enabling the delivery of the Facility's electrical energy to the Buyer. This agreement shall include but not be limited to an Interconnection Agreement with the Interconnection Provider and documentation from the Interconnection Provider approving the delivery of the Facility's energy to the Point of Delivery.

2.2.1 The Parties acknowledge and agree that the Interconnection Agreement(s) and the Interconnection Provider documentation shall be separate and free-standing documents and agreements and that the terms of this Agreement are not binding upon the Interconnection Provider.

2.2.2 Notwithstanding any other provision in this Agreement, nothing in the Interconnection Agreement(s) or the Interconnection Provider documentation shall alter or modify the Buyer's or Seller's rights, duties and obligations under this Agreement. This Agreement shall not be construed to create any rights between the Seller and the Interconnection Provider.

ARTICLE 3
PROJECT MILESTONES

3.1 The Seller shall meet all requirements of the first three (3) Project Milestones specified in Exhibit H (exploration schedule, exploration drilling, and resource report).

3.1.1 Within sixty (60) days of the date the resource report required under the third Project Milestone is provided to the Buyer, the Parties shall review the provided report and establish the estimated average annual net output (kW rating) of the Facility. Based upon this agreed upon kW rating, the Facility shall be developed as follows:

a.) If the report indicates that the geothermal resource is able to accommodate a Facility kW rating from 14,000 kW to 25,000 kW the Seller shall proceed with completion of the Facility as specified within this Agreement.

b.) If the report indicates that the geothermal resource is able to accommodate a Facility kW rating of less than 14,000 kW, the Seller within sixty (60) days of the date of the issuance of the resource report shall notify the Buyer of the Seller's 1) intent to proceed with development and construction of the Facility as specified within this Agreement, or 2) propose to the Buyer modifications of the existing Agreement, or 3) provide notification of termination of this Agreement. If the Seller provides no notification within the sixty (60) day period, the Seller shall be obligated to proceed with development and construction of this Facility as specified within this Agreement. If the report indicates the kW rating of the Facility shall be less than 10,000 kW, the Buyer reserves the right to terminate this Agreement within this sixty (60) day period. If after commercially reasonable efforts the Parties are unable to agree upon modifications proposed as specified in item 2) above, either Party may terminate this Agreement with 30 days notification. Upon mutual consent, the Parties may agree to extend this sixty (60) day period prior to the end of the initial sixty (60) day period. Termination of this Agreement as allowed with this section 3.1.1 b) shall result in no damages be assessed against either the Buyer or the Seller.

c.) If the report indicates that the geothermal resource is able to accommodate a Facility kW rating greater than 25,000 kW the Seller shall proceed with development of up to a 25,000 kW rated Facility. The Parties may mutually agree to Net Energy deliveries to the Buyer exceeding 25,000 kWh per hour as an amendment to this Agreement or in a separate agreement.

3.2 The Seller shall meet all requirements of the fourth Project Milestone (issuance of notice to proceed with power plant construction) specified in Exhibit H.

3.2.1 Within sixty (60) days of meeting the fourth Project Milestone, Seller may revise, if necessary, item B-1 of Appendix B. Any such revision shall provide sufficient detail to accurately describe the entire geothermal facility that will be included in this Agreement. This description must include, but not be limited to, generation equipment, cooling towers, control equipment, turbine, heat exchanger, geothermal fluid production and injection wells, geothermal fluid transportation system, etc.

3.2.2 Within sixty (60) days of meeting the fourth Project Milestone, Seller shall submit a revised Maximum Capacity value not to exceed the Maximum Capacity established in Section 1.38.

ARTICLE 4
CONDITIONS TO ACCEPTANCE OF ENERGY
FIRST ENERGY DATE

4.1 Conditions. As a condition of the Buyer's acceptance of deliveries of energy from the Seller, the following conditions shall be satisfied.

4.1.1 The Commission shall have approved this Agreement as contemplated in Articles 27 and 28, or Buyer shall have waived such approval.

4.1.2 Seller shall include updated information as to the Facility's expected First Energy Date in the Progress Reports and Seller shall have notified Buyer of the expected First Energy Date no later than five (5) Business Days before the expected First Energy Date.

4.1.3 Seller shall have delivered to the Buyer a certificate signed by an officer of Seller (1) certifying that to the best of the officer's knowledge all licenses, permits or approvals necessary for Seller's commencement of deliveries have been obtained from applicable federal, state or local authorities, and (2) listing all such licenses, permits and approvals.

4.1.3.1 Seller shall certify that either (a) the Seller's market-based tariff applicable for sale of the Test Energy and Net Energy has attained FERC Market-Rate authority or (b) the Facility is exempt from FERC Market-Rate authority and such application or acceptance is not required for Seller to commence Test Energy and Net Energy deliveries under this Agreement.

4.1.4 Opinion of Counsel. Seller shall have submitted to the Buyer an opinion letter signed by a law firm that includes attorneys admitted to practice and in good standing in the states of Idaho or Oregon providing an opinion that Seller's licenses, permits and approvals as set forth in Section 4.1.3 above are legally and validly issued, are held in the name of the Seller and, based on a reasonable review (which may include reliance on certificates provided by officers or other responsible personnel of Seller), the firm is of the opinion that Seller is in substantial compliance with said permits as of the date of the opinion letter. The opinion letter will be in a form acceptable to Buyer and will acknowledge that the firm rendering the opinion understands that Buyer is relying on said opinion in connection with and for the purposes of this transaction. Buyer's acceptance of the form will not be unreasonably withheld, conditioned or delayed. The opinion letter will be governed by and shall be interpreted in accordance with the legal opinion accord of the American Bar Association Section of Business Law (1991). If Buyer does not object in writing to the proposed form of opinion letter within ten (10) Business Days after receiving in it, it shall be deemed accepted.

4.1.5 Seller shall have delivered to Buyer certification that the Facility is substantially complete, tested and capable of beginning energy deliveries to the Buyer in a safe manner.

4.1.6 Engineer's Certifications. Submit an executed Engineer's Certification of Design & Construction Adequacy and an Engineer's Certification of Operations and Maintenance (O&M) Policy. These certificates will be in the form specified in Appendix E but may be modified to the extent necessary to recognize the different engineering disciplines providing the certificates.

4.1.7 Insurance. Submit written proof to the Buyer of all insurance required in Article 14.

4.1.8 Interconnection Provider Approval. Provide the Buyer with proof that the Interconnection Agreement is complete and all Interconnection Provider approvals, including approval for Seller to deliver Test Energy and Net Energy to the Metering Point of no less than the Maximum Capacity are complete.

4.1.9 Written Acceptance. Seller shall request and obtain written confirmation from the Buyer that all conditions to acceptance of Test Energy have been fulfilled. Such written confirmation shall be provided within a commercially reasonable time following the Seller's request and will not be unreasonably withheld by the Buyer.

The conditions set forth in this Section 4.1 are to be used solely for purposes of determining when the Facility has achieved its First Energy Date. They are not intended to affect in any way when the Facility is deemed to have been "placed in service" for tax treatment purposes.

4.2 Buyer's Approval of First Energy Date; Disagreements. Seller's designation of the First Energy Date shall be subject to Buyer's approval, which Buyer shall not unreasonably withhold, condition or delay. No later than five (5) Business Days after Seller's notification to the Buyer of the Seller's proposed First Energy Date, as specified in Section 4.1.9, Buyer shall send Seller a written notice, either (A) approving the First Energy Date specified in the notice, or (B) setting forth in reasonable detail Buyer's reasons for concluding that the First Energy Date has not been achieved or will be achieved on a date other than the date designated in Seller's notice. If Buyer does not respond on or before the fifth (5^{th}) Business Day after Seller's notice, the First Energy Date shall be deemed to have occurred on the date designated in Seller's notice. If Buyer reasonably disagrees that the First Energy Date has been achieved, the Parties shall cooperate promptly and in good faith to address Buyer's concerns and agree upon the First Energy Date. If the Parties are unable to agree to a First Energy Date within ten (10) Business Days of Buyer's notice of disagreement, either Party may pursue dispute resolution under Article 24 to determine the First Energy Date.

ARTICLE 5
TERM AND OPERATION DATE

5.1 Term.

5.1.1 Initial Term. This Agreement shall become effective as of the Effective Date and shall remain in full force and effect through the last day of the last month of the twenty-fifth (25^{th}) Contract Year , subject to any termination provisions set forth in this Agreement (the "Initial Term").

5.1.2 Buyer's Option to Extend Term. Buyer shall have the option to extend the Term. Buyer may exercise this option by giving irrevocable notice of exercise to Seller on or before the end of the twenty-third (23^{rd}) Contract Year. If Buyer does not timely exercise this option, the option shall automatically expire. The option set forth in this Section shall automatically terminate upon any termination of this Agreement. If Buyer timely exercises this option, the Parties will negotiate, in good faith, the terms and conditions under which the Term of this Agreement would be extended; *provided, however,* the option set forth in this Section shall terminate without liability to either Party if the Parties fail to enter into a definitive written agreement concerning the extension to the Term within six (6) months following the date of Buyer's notice. The terms and conditions of any such extension shall be subject to the Parties' respective management, Board of Directors, and any required Commission approval.

5.2 Progress Reports. On the first Business Day of each calendar quarter following the first Project Milestone (exploration report) until the Seller has achieved the fourth Project Milestone (power plant notice to proceed) and on the first Business Day of each calendar month thereafter until the Operation Date is achieved, Seller shall submit to the Buyer progress reports on the development and construction of the planned Facility in a form reasonably satisfactory to the Buyer. These Progress Reports shall include, but not be limited to, a project development schedule including all significant activities and milestones and the status of these items, notation and explanation of any significant delays and the Seller's planned action, and other information pertinent to Seller's progress on development and construction of the Facility.

5.3 Monitoring of Facility. Buyer shall have the right at its sole risk and expense to monitor the construction, start-up and testing of the Facility and the Seller shall comply with all reasonable requests of the Buyer with respect to these monitoring events. Seller shall cooperate in such physical inspections of the Facility as may be reasonably requested by the Buyer during and after completion of construction. All persons visiting the Facility on behalf of the Buyer shall comply with all of the Seller's applicable safety and health rules and requirements. Buyer's technical review and inspection of the Facility shall not be construed as endorsing the design of the Facility nor as any warranty of the safety, durability, or reliability of the Facility.

5.4 Operation Date. Seller will in good faith seek to achieve the Operation Date by the Scheduled Operation Date. The Operation Date shall occur after all of the following conditions have been satisfied.

5.4.1 Seller shall notify the Buyer of the Seller's proposed Operation Date, in written form no later than five (5) Business Days prior to the proposed Operation Date.

5.4.2 Seller shall have completed and shall have maintained all conditions to acceptance of energy as specified in Article 4.

5.4.3 The generator, turbines, extraction wells, injection wells and other associated equipment enabling the Facility to deliver at least 3,000 kW of Net Energy in a stable, reliable, consistent and safe manner have been installed, tested and determined to be functioning properly.

5.4.4 All Facility systems necessary for the stable, safe, reliable and consistent operation of the installed Facility are substantially complete, any testing of the installed Facility required pursuant to the Interconnection Agreement(s) and Interconnection Provider documents and equipment supplier requirements have been successfully completed, and the Facility is available for operation in all material respects in accordance with applicable laws.

5.4.5 Seller shall have delivered to Buyer a "Certificate of Facility Completion" signed by an officer of Seller certifying that the requirements of Sections 5.4.3 and 5.4.4 have been satisfied with respect to the Facility.

5.4.6 Seller shall have requested and obtained written confirmation from the Buyer that all conditions to receiving an Operation Date have been fulfilled. Such written confirmation shall be provided within a commercially reasonable time following the Seller's request and will not be unreasonably withheld by the Buyer.

These Operation Date requirements are to be used solely for purposes of determining when the Facility has achieved its Operation Date. They are not intended to affect in any way when the Facility is deemed to have been "placed in service" for purposes of PTC eligibility.

5.5 Buyer's Approval of Operation Date; Disagreements. Seller's designation of the Operation Date shall be subject to Buyer's approval, which Buyer shall not unreasonably withhold, condition or delay. No later than five (5) Business Days after Seller's notification to the Buyer of the Seller's proposed Operation Date, as specified in Section 5.4.6, Buyer shall send Seller a written notice, either (A) approving the Operation Date specified in the notice, or (B) setting forth in reasonable detail Buyer's reasons for concluding that the Operation Date has not been achieved or will be achieved on a date other than the date designated in Seller's notice. If Buyer does not respond on or before the fifth (5^{th}) Business Day after Seller's notice, the Operation Date shall be deemed to have occurred on the date designated in Seller's notice. If Buyer reasonably disagrees that the Operation Date has been achieved, the Parties shall cooperate promptly and in good faith to address Buyer's concerns and agree upon the Operation Date. If the Parties are unable to agree to an Operation Date within ten (10) Business Days of Buyer's notice of disagreement, either Party may pursue dispute resolution under Article 24 to determine the Operation Date. Upon completion of the dispute resolution process establishing an Operation Date and/or upon mutual agreement between the Parties of an Operation Date, the Buyer shall revise any previous Net Energy payments to reflect the applicable Net Energy Price from the date of the agreed upon Operation Date.

5.6 Continuing Obligations. Seller shall provide Buyer with the following during the Term of this Agreement:

5.6.1 At Buyer's request, Seller shall provide evidence that it is in compliance with the insurance requirements set forth in Section 14.2.

5.6.2 Seller shall maintain compliance and remain in good standing in all requirements of Articles 4 and 5 of this Agreement.

ARTICLE 6
PRICE

6.1 Test Energy Price. Notwithstanding any other energy pricing provisions in the Agreement, Buyer shall pay the Seller the lesser of the current month Market Energy Price or Contract Price for each kWh of Test Energy.

6.2 Net Energy Price. For all Net Energy delivered by the Seller to the Buyer from the Operation Date through the end of the Initial Term, Buyer shall pay the Seller the Contract Price.

6.3 Contract Price, Terms and Conditions to Remain in Effect for Term. The prices, terms and conditions specified in this Agreement shall remain in effect until expiration of the Term. Notwithstanding any provision in this Agreement, neither Party shall seek, nor shall support any third party in seeking, to prospectively or retroactively revise the prices, terms or conditions of service of this Agreement through application or complaint to FERC pursuant to the provisions of Section 205, 206 or 306 of the Federal Power Act, or any other provisions of the Federal Power Act, absent the prior written agreement of the Parties. Further, absent the prior agreement in writing by both Parties, the standard of review for changes to the prices, terms and conditions of service of this Agreement proposed by a Party, a non-Party or the FERC acting *sua sponte* shall be the "public interest" standard of review set forth in *United Gas Pipe Line Co. v. Mobile Gas Service Corp.*, 350 US 332 (1956) and *Federal Power Commission v. Sierra Pacific Power Co.*, 350 US 348 (1956).

ARTICLE 7
ENVIRONMENTAL ATTRIBUTES

7.1 Environmental Attributes. Buyer will be granted ownership of all of the Environmental Attributes associated with the Facility. Title of all Environmental Attributes shall pass to Buyer at the same time that transfer of title of the associated Test Energy or Net Energy to Buyer occurs. If after the Effective Date any additional Environmental Attributes or similar environmental value is created by legislation, regulation, or any other action, including but not limited to, carbon credits and carbon offsets, Buyer shall be granted ownership of all of these additional Environmental Attributes or environmental values that are associated with the Test Energy or the Net Energy delivered by the Seller to Buyer. All reasonable costs of securing the ownership of these additional Environmental Attributes and environmental values, including documented Seller costs, shall be paid by the Buyer.

Seller shall use prudent and commercially reasonable efforts to ensure that any operations of the Facility do not jeopardize the current or future Environmental Attribute status of this geothermal generation Facility.

7.2 The Parties shall cooperate to ensure that all Environmental Attribute certifications, rights and reporting requirements are completed by the responsible Parties.

7.2.1 At least sixty (60) days prior to the First Energy Date, the Parties shall mutually cooperate to enable the Environmental Attributes from this Facility to be placed into the Buyer's WREGIS account or any other Environment Attribute accounting and tracking system selected by the Buyer. The Buyer shall reimburse the Seller for any WREGIS or other Environmental Attribute system fees incurred to enable this to occur and/or any reoccurring WREGIS or other Environmental Attribute system fees for the Term of this Agreement. If the Environmental Attribute accounting and tracking system initially selected by the Buyer is materially altered or discontinued during the Term of this Agreement, the Parties shall cooperate to identify an appropriate alternative Environmental Attribute accounting and tracking process and enable the Environmental Attributes be processed through this alternative method.

7.2.2 The Seller shall not report under Section 1605(b) of the Energy Policy Act of 1992 or under any applicable program that any Environmental Attributes are owned by the Seller.

7.2.3 As the Buyer is the sole owner of the Environmental Attributes from this Facility, only the Buyer shall be entitled to sell, trade, assign or otherwise transfer or claim the Facility's Environmental Attributes.

7.2.4 If the Buyer requests additional Environmental Attribute certifications beyond what is provided by the WREGIS process the Seller shall obtain any Environmental Attribute certifications required by the Buyer for those Environmental Attributes delivered to the Buyer from the Seller. If the Seller incurs cost, as a result of a Buyer's request, Seller shall invoice the Buyer for the reasonable costs of providing such certification. If the Buyer elects to obtain its own certifications, then Seller shall fully cooperate with the Buyer in obtaining such certification.

ARTICLE 8
DELIVERY AND SHORTFALL OBLIGATIONS

8.1 Delivery and Acceptance of Test Energy. Except when either Party's performance is excused as provided herein, the Buyer will purchase and Seller will sell the Test Energy produced by the Facility.

8.2 Delivery and Acceptance of Net Energy. Except when either Party's performance is excused as provided herein, the Buyer will purchase and Seller will sell the Net Energy produced by the Facility.

8.3 No Deliveries In Excess of the Maximum Capacity. Under no circumstances will the Seller deliver Net Energy and/or Test Energy to the Metering Point in an amount that (1) exceeds 36,000 kW at any moment in time or (2) that exceeds the Maximum Capacity by any amount for more than five (5) consecutive minutes. Delivery of Net Energy and/or Test Energy by the Seller to the Metering Point that exceeds either item (1) or (2) of this section shall be a Material Breach of this Agreement. Any Material Breach of this Agreement arising under this Section 8.3 may be cured by the Seller reducing the Net Energy or Test Energy deliveries to the Buyer to no longer exceed the limits established in this section. In addition, the Seller shall identify the circumstances that caused the Facility to deliver energy in excess of these limitations and implement the necessary operational procedures to prevent similar deliveries in excess of these limits. If the Seller repeatedly exceeds these limits and is not taking commercially reasonable efforts to resolve this issue, the Buyer may terminate this Agreement.

8.4 Forecasting. At its expense, Seller shall provide to Buyer for the Term, forecasting information provided via electronic format acceptable to the Buyer or any other format that the Buyer and Seller mutually agree is acceptable. The Seller shall be responsible for all costs associated with creating and transmitting the forecasting information to the Buyer. Each forecast will take into account any Scheduled Outages, any known Forced Outages, known curtailments or known capacity deratings affecting the Facility. The Buyer and Seller shall mutually develop and approve the electronic format and process of transmitting the data no later than thirty (30) days prior to the Operation Date. The forecasting information shall be provided as follows:

(1) No later than 1:00 pm Pacific Time each Business Day, the Seller shall provide an hourly forecast that starts at 5:00 am Pacific Time of the next day and runs for a minimum of 168 hours (7 days).

(2) Any deviations exceeding or equal to plus or minus ten percent (10%) of the previously provided forecast will be communicated to the Buyer in a prompt and timely manner. In the case of a planned event the Seller shall notify the Buyer by 5:00 pm Pacific Time of the preceding day of any Net Energy forecasting deviation of the previously provided forecast. In the case of an unplanned event, the Seller shall notify the Buyer promptly after the occurrence of the unplanned event. In both cases, the Seller will include with this notification the expected duration and quantity of the energy delivery reductions that will occur at the Metering Point.

8.4.1 Basis of Forecasts. The forecasts called for by this Agreement shall be consistent with any specific requirements of this Agreement, geothermal industry standards and Good Utility Practice(s).

8.4.2 Provision of Forecasting. The provision of the forecasting information described in Section 8.4 in accordance with Good Utility Practice(s) is an integral component of this Agreement. Accordingly, Seller shall act in a manner consistent with Good Utility Practice(s) with the goal of providing timely, useful, quality forecasts to the Buyer under Section 8.4. If Seller fails in any material respect to act in conformity with the preceding sentence, Buyer may provide notice to Seller stating in reasonable detail the basis for Buyer's belief that Seller is defaulting in its obligations under this Article 8. Seller shall have ten (10) Business Days in which to cure the alleged default, to commence the cure of the alleged default if it cannot reasonably be cured within the ten (10) Business Day period (and thereafter diligently pursue such cure to completion), or to submit the matter to dispute resolution under Article 24. With respect to any Facility Lender or Investor, the ten (10) Business Day periods set forth in the preceding sentence shall be extended to thirty (30) days from date of Buyer's notice to Seller under this Section 8.4. As long as Seller is pursuing dispute resolution under Article 24 in good faith, Seller shall not be in default of this Section and shall have sixty (60) days from any final resolution of the dispute in which to implement any agreed-upon or required cure ("Forecast Cure Period").

8.5 Output Guarantee

8.5.1 By December 1st of each calendar year, the Seller shall submit in writing to the Buyer the identity of a licensed professional independent engineer or licensed professional independent engineering firm and the independent engineer or engineering firm's qualifications that the Seller intends to contract with to complete the annual certification as required in this Section. The Seller shall be responsible for all costs of retaining this engineer and the cost of completing the certification as required within this Section. No later than ten (10) Business Days after Seller's notification to the Buyer of the Seller's proposed independent engineer or independent engineering firm, Buyer shall send Seller a written notice, either (A) approving the independent engineer or independent engineering firm specified in the notice, or (B) setting forth in reasonable detail Buyer's reasons for concluding that the independent engineer or independent engineering firm selected by the Seller is not acceptable. If Buyer does not respond on or before the end of the tenth (10th) Business Day after Seller's notice, the independent engineer or the independent engineering firm selected by the Seller shall be deemed to be acceptable. If Buyer reasonably disagrees that the Seller selected independent engineer or independent engineering firm is acceptable, the Parties shall cooperate promptly and in good faith to address Buyer's concerns and agree upon an independent engineer or independent engineering firm. If the Parties are unable to agree to an independent engineer or independent engineering firm within ten (10) Business Days of Buyer's notice of disagreement, either Party may pursue dispute resolution under Article 24 to determine an independent engineer.

8.5.2 No later than February 1st of each calendar year, the Seller will provide the Buyer with a report and an energy forecast, stamped and approved by the professional independent engineer or the independent engineering firm specified above, containing at the minimum, certification of the following:

a) Current status of the geothermal resource in comparison to the previous status of the resource. This information will include a detailed description of any geothermal resource degradation, the apparent cause of such degradation, assessment of future status of the resource and its ability to sustain its current level of output in consideration of the requirements of Section 8.7.

b) Estimated lost Net Energy (measured in kWh) production associated with Scheduled Outages as specified in Section 1.58 that are planned to occur for the next twenty-four (24) months beginning with March 1st of the current year.

c) Estimated energy (measured in kWh) that the Facility will be able to deliver to the Metering Point for each of the next twenty-four (24) months beginning with March of the current year.

d) The assumptions used by the engineer.

8.5.3 No later than ten (10) Business Days after Seller provides a written copy of the certification as specified above to the Buyer, the Buyer shall send Seller a written notice, either (A) approving the certification, or (B) setting forth in reasonable detail Buyer's reasons for concluding that the certification is not acceptable. If Buyer does not respond on or before the end of the tenth (10th) Business Day after Seller's notice, the certification provided by the Seller shall be deemed to be acceptable. If Buyer reasonably disagrees that the Seller's certification is acceptable, the Parties shall cooperate promptly and in good faith to address Buyer's concerns and agree upon a certification. If the Parties are unable to agree on the certification as being acceptable within ten (10) Business Days of Buyer's notice of disagreement, either Party may pursue dispute resolution under Article 24 to determine an acceptable certification.

8.5.4 The "Annual Output Forecast" (measured in kWh) shall be the lower of (i) the sum of the monthly estimated energy established in Section 8.5.2 c) for the first twelve (12) months of the information provided or (ii) the Expected Annual Average Capacity established in Appendix B, multiplied by 8,760 hours and then by the Annual Capacity Factor. The last Annual Output Forecast of the Initial Term of this Agreement shall be based upon the actual Calendar Months available for the project to deliver Net Energy from March 1st to the last day of the Initial Term of this Agreement, which may or may not be a full twelve (12) months.

8.5.4.1 For the period beginning with March 1st of the first (1st) Contract Year through February 28th of the third (3rd) Contract Year an Annual Output Forecast shall be provided for information purposes only and no Net Energy Shortfall will be calculated for this period.

8.5.4.2 Upon conclusion of an event that causes energy deliveries to the Buyer to be reduced, the Seller shall calculate the quantity of energy delivery reductions they believe occurred due to the event. These events shall include Forced Outages, *force majeure*, actual Scheduled Maintenance outages, curtailments required by the Buyer or curtailments required by the Interconnection Provider. Upon mutual agreement as to the quantity of energy delivery reduction, the Annual Guaranteed Output shall be adjusted accordingly.

8.5.5 Energy Delivery Guarantee, Reconciliation, and Net Energy Shortfall Determination. Seller guarantees that the Total Annual Facility Net Energy shall equal or exceed the Annual Guaranteed Output for each Contract Year during the Initial Term of this Agreement beginning with March 1st of the fourth (4th) Contract Year. The determination of whether Seller has met its Annual Guaranteed Output requirement shall be made on an annual basis beginning on March 1st of the fifth (5th) Contract Year by comparing the amount of the previous twelve (12) month's Total Annual Facility Net Energy to the Annual Guaranteed Output as provided for in this Section.

8.5.5.1 If the Total Annual Facility Net Energy is equal to or greater than the Annual Guaranteed Output in the applicable period, Seller shall be deemed to have met its Annual Guaranteed Output obligation for that period, and Seller shall have no obligation to pay Net Energy Shortfall Damages or to true-up energy delivery obligations with respect to that period. Any Net Energy delivered during this period exceeding the Annual Guaranteed Output may be used to make up the previous period Net Energy Shortfall if one exists.

8.5.5.2 If the Total Annual Facility Net Energy is less than the Annual Guaranteed Output for a specified period, then a Net Energy Shortfall exists and is equal to the Annual Guaranteed Output minus the Total Annual Facility Net Energy. The Net Energy Shortfall may be made up in the subsequent twelve (12) month period beginning at March 1st. Net Energy delivered during the immediately following twelve (12) month period in excess of the Annual Guaranteed Output for that period may be used to make up the previous period's Net Energy Shortfall. At the end of the subsequent twelve (12) month period, if the Net Energy Shortfall has not been made up, then any remaining Net Energy Shortfall Damages will be calculated based upon any remaining balance of the Net Energy Shortfall and a billing will be presented to the Seller which the Seller will be required to pay the Buyer within fifteen (15) days of the date of the billing notice.

Any remaining Net Energy Shortfall at the end of the Initial Term of this Agreement will be payable to the Buyer within fifteen (15) days of the date of the billing notice being provided to the Seller.

8.6 <u>Buyer Acceptance of Energy, Excused Payment, Payment for Unexcused Curtailments and Adjustment of the Annual Guaranteed Output</u>

8.6.1 Acceptance of Energy –

a.) The Buyer shall be excused from accepting Net Energy and Test Energy for any reason.

8.6.2 Excused Energy Payment –

a.) The Buyer shall be excused from paying for Net Energy and Test Energy that the Buyer did not accept in any Contract Year due to an event of Force Majeure or that is equal to or less than the Annual Allowed Energy Reduction. Net Energy and Test Energy that is not accepted by the Buyer due to an event of Force Majeure is not included in the calculation of MWh's not accepted by the Buyer in determining if the Buyer has exceeded the Annual Allowed Energy Reduction.

b.) The Buyer shall not be excused from paying for Net Energy and Test Energy that the Buyer did not accept due to an economic dispatch.

8.6.3 Payment for Unexcused Curtailment –

a.) If the Buyer fails to accept Net Energy or Test Energy that the Facility could have delivered, and payment for the unaccepted energy is not excused as specified in section 8.6.2 a), then the Buyer shall pay the Seller the applicable Contract Price or Test Energy Price plus any applicable PTC Value for the estimated Net Energy and/or Test Energy that the Seller was unable to deliver to the Buyer. The estimated Net Energy and/or Test Energy (measured in kWh) that was not delivered will be determined based upon the most recently provided energy forecast, prior to the curtailment, as specified in Section 8.4 of this Agreement for the applicable time period in which the Buyer did not accept the Seller's energy. If the curtailment event exceeds the time period of the energy forecast (168 hours) the Buyer and Seller shall mutually agree upon the estimated Net Energy and/or Test Energy based upon the most recently provided energy forecast plus any additional information available.

b.) If the Buyer does not accept the Net Energy from this Facility, then Seller may attempt to sell all or a portion of the Net Energy to another party for just the period of when Buyer is not accepting the Net Energy from the Facility. Seventy-five percent (75%) of any net energy sales payments the Seller receives from another party will be deducted from any payments the Buyer is required to make to the Seller for the period in which the Buyer was not accepting the Facility's Net Energy.

8.6.4 Adjustment of Guaranteed Output –

If the Buyer requires the Seller to reduce Net Energy deliveries to the Buyer from the Facility pursuant to the terms of this Article 8.6, the Annual Guaranteed Output for the impacted Contract Year(s) will be reduced by the same amount as the estimated Net Energy that was not delivered as a result of the Buyer's curtailment requirements.

8.7 Requirements for the Addition of New Geothermal Energy Uses.

Seller may add additional uses of geothermal energy controlled by Seller or available for Seller's use, subject to the terms of this Section 8.7.

8.7.1 Certification of Geothermal Energy Sufficiency. Prior to allowing each new geothermal use(s) to be built and delivery of geothermal energy to commence to the new geothermal use(s), an independent licensed geothermal reservoir engineer shall certify that for the remaining Term of this Agreement and in the professional judgment of this engineer, the geothermal energy production capability of the geothermal resource controlled by Seller or available for Seller's use is sufficient to supply at least one hundred percent (100%) of the geothermal energy requirements of (1) the Facility, (2) the existing other use(s) of geothermal energy, and (3) the proposed new use(s) of the geothermal energy.

8.7.1.1 The independent engineer shall be selected by Seller and shall be reasonably acceptable to Buyer. The Seller shall be responsible for all costs of retaining this engineer and the cost of completing the certification as required within this Section.

8.7.1.2 Seller shall provide Buyer with a copy of the independent engineer's certification prior to adding any additional geothermal uses. Buyer shall have sixty (60) days to provide Seller with the Buyer's acceptance or rejection of such certification. If rejected, the Buyer will supply Seller the reason(s) why the certification was rejected and the necessary modifications required to make the certification acceptable.

8.7.1.3 Geothermal energy use(s) that utilize waste heat from the Facility and do not materially affect the power operations of the Facility may be installed by Seller.

8.8 Title and Risk of Loss. As between the Parties, Seller shall be deemed to be in control of the energy output from the Facility up to and until delivery and acceptance at the Metering Point by the Buyer. Title and risk of loss related to the energy shall transfer from Seller to Buyer at the Metering Point.

8.9 Station Energy. Seller shall enter into separate arrangements for the supply of electric services to the Facility to supply Station Energy when the Facility's generation is unable to meet the Station Energy requirements. Seller is responsible for causing these electric services to be available before the First Energy Date. Seller will specifically design the Facility to ensure that no energy purchased for supply of electric energy to the Facility is delivered to the Buyer as Net Energy or Test Energy.

ARTICLE 9
METERING AND TELEMETRY

9.1 Metering and Telemetry. Seller will arrange for the Interconnection Provider to provide, install, and maintain Metering and Telemetry Equipment to be located at the Metering Point to accurately calculate the actual energy deliveries from the Seller to the Metering Point and provide continuous telemetry information from the Facility to the Interconnection Provider and the Buyer. The Metering and Telemetry Equipment shall be of the type required to accurately measure, record and report the energy to provide the Buyer adequate Net Energy and Test Energy measurement data to administer this Agreement and to integrate the Facility's energy into the Interconnection Provider's electrical system. The Buyer shall not be responsible for any costs of the actual Metering and Telemetry Equipment, installation, inspections, maintenance and testing costs.

9.2 Seller will arrange for and make available at Seller's cost a communication circuit acceptable to the Interconnection Provider and the Buyer, dedicated to Interconnection Provider and the Buyer's use to be used for load profiling and another communications circuit dedicated to Interconnection Provider and Buyer's communication equipment for continuous telemetering of the Facility's energy deliveries to Designated Dispatch Facility. Interconnection Provider and Buyer provided equipment will be owned and maintained by either the Interconnection Provider or the

Buyer. The Buyer shall be not be responsible for any of the cost of purchase, installation, operation, and maintenance, including administrative cost of this equipment.

9.3 All meters used to determine the billing hereunder shall be sealed and the seals shall be broken only by the Interconnection Provider or the Buyer when the meters are to be inspected, tested or adjusted.

9.4 Meter Inspection. Seller will arrange for the Interconnection Provider to inspect the Metering and Telemetry installations regularly and test meters on the applicable periodic test schedule relevant to the Metering and Telemetry Equipment installed. If requested by the Seller, the Interconnection Provider shall make a special inspection or test of a meter and the Seller shall pay the reasonable costs of such special inspection. The Seller shall make arrangements with the Interconnection Provider to be notified at least two (2) Business Days prior to the time when any inspection or test shall take place, and the Seller may have representatives present at the test or inspection. If a meter is found to be inaccurate or defective, it shall be adjusted, repaired or replaced, at the Seller's expense, in order to provide accurate metering. If a meter fails to register, or if the measurement made by a meter during a test varies by more than two percent (2%) from the measurement made by the standard meter used in the test, adjustment (either upward or downward) to the payments Seller has received shall be made to correct those payments affected by the inaccurate meter for the actual period during which inaccurate measurements were made. If the actual period cannot be determined, corrections to the payments shall be based on the shorter of (1) a period equal to one-half (1/2) the time from the date of the last previous test of the meter to the date of the test which established the inaccuracy of the meter; or (2) six (6) months. Seller shall state such adjustment as a credit or additional charge, as appropriate, on its next invoice.

9.5 Additional Telemetry. If the Buyer requests telemetry equipment, information or services of any nature beyond that expressly required by the Interconnection Provider, the Seller and Buyer shall mutually cooperate to make efficient use of Seller's, Interconnection Provider's and Buyer's telemetry equipment to provide the additional information requested by Buyer in the most cost-effective manner. The Seller shall not be responsible for any cost associated with additional telemetry equipment, information, services or requirements that are beyond those expressly required by the Interconnection Provider.

ARTICLE 10
SYSTEM PROTECTION

10.1 Operation and Maintenance of Seller's Facilities. Seller shall construct, operate and maintain the Facility and Seller's Interconnection Facilities in accordance with the Interconnection Providers' requirements, Good Utility Practice(s), the National Electrical Code, the National Electrical Safety Code, and any other applicable local, state and federal codes.

ARTICLE 11
FACILITY AND INTERCONNECTION

11.1 Design of Facility. Seller will design, construct, install, own, operate and maintain the Facility and any Seller-owned Interconnection Facilities so as to allow safe and reliable generation and delivery of energy to the Buyer for the full Term of the Agreement.

11.2 Interconnection Facilities. Seller will construct, install, own and maintain all Interconnection Facilities other than those owned, installed or maintained by the Interconnection Provider. Buyer will not be responsible for any costs of interconnecting the Seller's Facility with the Interconnection Provider.

ARTICLE 12
GENERAL OPERATIONS

12.1 Communications. Seller, Interconnection Provider and Buyer shall maintain appropriate operating communications through the Designated Dispatch Facility in accordance with Appendix F.

12.2 Scheduled Maintenance. On or before March 1st of each calendar year, Seller shall submit a written proposed maintenance schedule of significant Facility maintenance for the next twelve (12) months, beginning with March 1st of the current year, and Buyer and Seller shall mutually agree as to the acceptability of the proposed schedule. The Parties determination as to the acceptability of Seller's timetable for scheduled maintenance will take into consideration the need to perform maintenance and perform other work as required to maintain the Facility's reliable operations, Good Utility Practice(s), Buyer's system requirements, Interconnection Provider's maintenance schedule, Buyer's maintenance schedule and Seller's preferred schedule. Neither Party shall unreasonably withhold acceptance of the proposed maintenance schedule. Upon mutual agreement between the Parties, or otherwise if required by Good Utility Practices, the previously approved Scheduled Maintenance may be revised during a Contract Year.

12.3 Maintenance Coordination. Buyer and Seller shall mutually cooperate, to the extent practical, to coordinate the Facility's maintenance schedules with the Interconnection Provider's maintenance schedules and the Buyer's maintenance schedules such that they occur simultaneously.

12.4 Contact Prior to Curtailment. The Buyer will make a reasonable attempt to contact Seller prior to exercising its rights to curtail, interrupt or reduce deliveries from the Seller's Facility. Seller understands that in the case of emergency circumstances, real time operations of the electrical system, and/or unplanned events, the Buyer may not be able to provide notice to the Seller prior to interruption, curtailment, or reduction of electrical energy deliveries to the Buyer.

ARTICLE 13
BILLING, RECORDS, AUDITS

13.1 Billing Invoices. The monthly billing period shall be the calendar month. No later than three (3) Business Days after the end of each calendar month, Seller shall provide to Buyer, by e-mail or fax and confirmed by first-class mail, an invoice for the amount due Seller by Buyer for the previous calendar month billing period. Seller's invoice shall show all billing parameters, rates and factors, and any other data reasonably pertinent to the calculation of monthly payments due to the Seller. Each such monthly invoice shall calculate the amount that Buyer owes to the Seller for Test Energy, Net Energy and any offsets for Net Energy Shortfall Damages. Upon receipt of this invoice, Buyer shall review and confirm all calculations and contact the Seller with any identified discrepancies.

13.2 Payments. Unless otherwise specified in this Agreement, undisputed payments due under this Agreement shall be due and payable by electronic funds transfer on or before the twenty-fifth (25th) day of the invoicing month or fifteen (15) days after receipt of the billing statement from the Seller by the Buyer, whichever is later. If the due date occurs on a day that is not a Business Day, payment will be due on the next Business Day. If the undisputed amount due is not paid on or before the due date, a late payment charge shall be applied to the unpaid balance and shall be added to the next billing statement. Such late payment charge shall be calculated based on the Interest Rate. Buyer shall have the right to withhold from the payment any unpaid and undisputed Seller amounts due to Buyer.

13.3 Maintenance of Records. Seller shall maintain at the Facility or such other location mutually acceptable to the Parties adequate total generation, net generation, and maximum generation (kW) records in a form and content consistent with Good Utility Practice(s).

13.4 Right to Audit; Refunds; Billing Disputes.

13.4.1 Audit Rights. Each Party shall have the right, upon reasonable notice to the other Party and during the other Party's regular business hours and without unduly interfering with the conduct of that Party's business, to access all of that Party's records pertaining to invoices under this Agreement and to audit reports, data, calculations, invoices, Net Energy, and maximum generation records pertaining to the Facility. The auditing Party shall bear its own costs of performing such audit; *provided, however,* that the other Party shall cooperate with the audit and shall not charge the auditing Party for any reasonable costs (including without limitation the cost of photocopies) that the other Party may incur as a result of such audit. A Party shall have twenty-four (24) months from the date on which an invoice or notice is received to audit and to challenge that invoice or notice.

13.4.2 Refunds of Overpayments and Underpayments. If an audit discovers a billing error or errors that resulted in an overpayment by the Buyer, Seller shall refund to the Buyer the amount of the overpayment plus interest calculated at the Interest Rate thereon from the date such overpayment was made by the Buyer to (but not including) the date the Buyer actually receives the refund from the Seller. If the audit discovers a billing error or errors that resulted in an underpayment by the Buyer, the Buyer shall pay to the Seller the amount of the underpayment plus interest calculated at the Interest Rate thereon from the due date thereof to (but not including) the date the Seller actually receives the payment thereof from the Buyer. The Interest Rate used in this Section shall be the Interest Rate applicable to cash collateral.

13.4.3 Billing Disputes. Either Party may dispute invoiced amounts, but shall pay to the other Party at least the undisputed portion of invoiced amounts on or before the invoice due date. To resolve any billing dispute, the Parties shall use the procedures set forth in Article 24. When the billing dispute is resolved, the Party owing shall pay the amount owed within five (5) Business Days of the date of such resolution, with interest charges calculated on the amount owed in accordance with the provisions of Section 13.4.2. Buyer at any time may offset against any and all amounts that may be due and owed to Seller under this Agreement, any and all undisputed amounts, including damages and other payments, that are owed by Seller to Buyer pursuant to this Agreement. Likewise, Seller at any time may offset against any and all amounts that may be due and owed to Buyer under this Agreement, any and all undisputed amounts, including damages and other payments, that are owed by Buyer to Seller pursuant to this Agreement. Undisputed and non-offset portions of amounts invoiced under this Agreement shall be paid on or before the due date or shall be subject to the interest charges set forth in Section 13.4.2.

ARTICLE 14
INDEMNIFICATION AND INSURANCE

14.1 Indemnification. Each Party shall agree to hold harmless and to indemnify the other Party, its officers, agents, affiliates, subsidiaries, parent company and employees against all loss, damage, expense and liability to third persons for injury to or death of person or injury to property, proximately caused by the indemnifying Party's construction, ownership, operation or maintenance of, or by failure of, any of such Party's works or facilities used in connection with this Agreement. The indemnifying Party shall, on the other Party's request, defend any suit asserting a claim covered by this indemnity. The indemnifying Party shall pay all costs, including reasonable attorney fees that may be incurred by the other Party in enforcing this indemnity.

14.2 Insurance. During the Term of this Agreement, Seller shall secure and continuously carry the following insurance coverage:

14.2.1 Worker's Compensation Insurance. Seller shall, during the Initial Term of this Agreement and any extensions thereof, provide and maintain Worker's Compensation Insurance for all its employees engaged in work under this Agreement in accordance with statutory requirements. Seller shall obtain a Waiver of Subrogation Endorsement in favor of Buyer in reference to Worker's Compensation Insurance.

If any direct claim for Worker's Compensation benefits is asserted against Seller by any of Seller's employees or, in the event of the death of a Seller's employee, by such employee's personal representatives, then, upon timely written notice from Buyer, Seller shall undertake to defend Buyer against such claim(s) and shall indemnify and hold Buyer harmless from and against any such claim(s) to the extent of all benefits awarded.

14.2.2 Comprehensive General Liability Insurance (including coverage for bodily injury and death, property damage, independent contractors, products and completed operations) with limits equal to $1,000,000, each occurrence, combined single limit. The deductible for such insurance shall be consistent with current Insurance Industry Utility practices for similar property. Seller to obtain a Waiver of Subrogation Endorsement in favor of Buyer in reference to comprehensive general liability insurance.

14.2.3 Excess/Umbrella Liability Insurance with limits not less than $5,000,000.

14.2.4 If the Seller, in its sole discretion, elects to obtain Boiler and Machinery Insurance, Property Insurance or Business Interruption Insurance, the coverages and deductible shall be additionally declared on the annual insurance certification as required in section 14.3.

14.2.5 All of the above insurance coverages shall be placed with insurance companies with an A.M. Best rating of A- or better and shall include:

a) A Waiver of Subrogation Endorsement in favor of the Buyer.

b) With respect to Comprehensive General Liability Insurance and Excess/Umbrella Liability Insurance, an endorsement naming Buyer as an additional insured, and loss payee.

c) The policy shall include a provision stating that such policy shall not be canceled or the limits of liability reduced without sixty (60) days' prior written notice to Seller. Seller shall notify Buyer within five (5) Business Days after Seller receives any such notice.

14.3 Seller to Provide Certificate of Insurance. As required in Section 4.1.7 of this Agreement and annually thereafter, Seller shall furnish Buyer a certificate of insurance evidencing the coverage and required endorsements as set forth above.

14.4 Seller to Notify Buyer of Loss of Coverage. If the insurance coverage required by Section 14.2 shall lapse for any reason, Seller will immediately notify the Buyer in writing. The notice will advise the Buyer of the specific reason for the lapse and the steps the Seller is taking to reinstate the coverage.

14.5 Seller's Failure to Maintain Required Insurance. Seller's failure to maintain the insurance as required in this Article 14 shall be a Material Breach of this Agreement.

ARTICLE 15
CREDIT AND COLLATERAL REQUIREMENTS

15.1 Financial Information.

15.1.1 The Buyer shall make available electronically to the Seller (i) within one hundred-twenty (120) days following the end of a Buyer's fiscal year, a copy of the Buyer's audited consolidated financial statements for its fiscal year, and (ii) within sixty (60) days after the end of each of its first three (3) fiscal quarters of each fiscal year, a copy of the Buyer's unaudited consolidated financial statements for such fiscal quarter. In all cases, the statements shall be for the most recent accounting period and prepared in accordance with generally accepted accounting principles, consistently applied; *provided, however,* that should any such statements not be available on a timely basis due to a delay in preparation or certification, such delay shall not be an Event of Default so long as the Buyer diligently pursues the preparation of the statements. This Financial Information is available on the Buyer's website www.idahopower.com. Buyer's assistance in guiding the Seller to this information on the Buyer's website will be satisfaction of this requirement.

15.1.2 The Seller shall make available electronically to the Buyer (i) within one hundred-twenty (120) days following the end of U.S. Geothermal's fiscal year, a copy of U.S. Geothermal's audited consolidated financial statements for its fiscal year, and (ii) within sixty (60) days after the end of each of its first three (3) fiscal quarters of each fiscal year, a copy of U.S. Geothermal's unaudited consolidated financial statements for such fiscal quarter. In all cases, the statements shall be for the most recent accounting period and prepared in accordance with generally accepted accounting principles, consistently applied; *provided, however,* that should any such statements not be available on a timely basis due to a delay in preparation or certification, such delay shall not be an Event of Default so long as the Seller diligently pursues the preparation, certification and delivery of the statements. This Financial Information is available on the Seller's website www.usgeothermal.com. Seller's assistance in guiding the Buyer to this information on the Seller's website will be satisfaction of this requirement.

15.1.3 If during the Term of this Agreement any of the financial statements required in Sections 15.1.1 or 15.1.2 are not publicly available, the Parties shall mutually agree to confidentially agreements to allow exchange of confidential information and/or alternative reporting that is acceptable documentation in lieu of the documents required in Sections 15.1.1 and 15.1.2.

15.2 Seller's Performance Assurances.

15.2.1 Exploration Performance Assurance. Within fifteen (15) Business Days after the Seller fails to satisfy the second or third Project Milestones identified in Appendix H, the Seller shall provide evidence to Buyer that Performance Assurance in the amount of no less than $100,000 has been established and will be maintained until such time as 1) this Agreement has been terminated, at which time the Seller will forfeit the $100,000 Performance Assurance to Buyer, or 2) all Seller Project Milestone defaults have been cured, at which time any rights the Buyer has to this specific Performance Assurance will be released. Upon the Seller's default of these Project Milestones, Notice of Default and the Default cure provisions as specified in Section 25.2 shall apply.

15.2.2 Development Performance Assurance - Within fifteen (15) Business Days after the Seller fails to satisfy the fourth Project Milestone (power plant engineer, procure, and construct notice to proceed) identified in Appendix H, the Seller shall provide evidence to Buyer that Performance Assurance in the amount of no less than $250,000 has been established and will be maintained until such time as this Agreement has been terminated at which time the Seller shall forfeit this $250,000 Performance Assurance to the Buyer. If the Seller is able to demonstrate that the Seller after commercially reasonable efforts was unable to achieve this Project Milestone due to its inability to obtain project financing, the Buyer may still terminate the Agreement but the $250,000 Performance Assurance shall not be forfeited to the Buyer. If all Seller Project Milestone defaults have been cured, any rights the Buyer has to this specific Performance Assurance will be released. Upon the Seller's default of this Project Milestone, Notice of Default and the Default cure provisions as specified in Section 25.2 shall apply.

15.2.3 Delay Performance Assurance - If the Facility does not achieve its First Energy Date within ninety (90) days of the Scheduled First Energy Date, the Seller shall within fifteen (15) Business Days provide evidence to Buyer that Performance Assurance in the amount of no less than $250,000 has been established and will be maintained until such time as 1) this Agreement has been terminated and all damages due the Buyer have been satisfied, or 2) all Seller defaults and Material Breaches have been cured, the First Energy Date has been achieved and all damages due to the Buyer have been satisfied, at which time any rights the Buyer has to this specific Performance Assurance will be released.

15.2.4 Operational Performance Assurance - If a Net Energy Shortfall as determined by Section 8.5.5 exceeds thirty percent (30%) of the Annual Guaranteed Output, the Seller shall within fifteen (15) Business Days provide evidence to Buyer that Performance Assurance in the amount of no less than $250,000 has been established and will be maintained until such time as 1) this Agreement has been terminated and all damages due the Buyer have been satisfied, or 2) all Seller defaults and Material Breaches have been cured, the Facility has met or exceeded its Annual Guaranteed Output for two (2) consecutive Contract Years and no outstanding Net Energy Shortfall exists, at which time any rights the Buyer has to this specific Performance Assurance will be released.

15.3 If Performance Assurance is required, the Seller shall provide one or a combination of the following as Performance Assurance(s).

15.3.1 Cause Seller's Guarantor to execute and deliver to the Buyer a Guaranty which is substantially in the form set forth as Appendix C (or, at Seller's discretion, cause another guarantor that is not experiencing a Material Adverse Change to execute and deliver to the Buyer a Guaranty which is substantially in the form set forth as Appendix C or in another form acceptable to the Buyer); or

15.3.2 Establish and maintain at the Seller's expense an escrow account for the benefit of the Buyer in a form reasonably acceptable to the Buyer; or

15.3.3 Provide a cash deposit to the Buyer; or

15.3.4 Provide a letter of credit in a form reasonably acceptable to the Buyer.

15.4 Grant of Security Interest in Certain Collateral and Security. To secure its obligations under this Agreement, Seller hereby grants to Buyer, a present and continuing security interest in, and lien on (and right of setoff against), and assignment of, all cash collateral and cash equivalent collateral and any and all proceeds resulting therefrom or the liquidation thereof, whether now or hereafter held by, on behalf of, or for the benefit of, the secured Party. Seller shall take such action as Buyer reasonably requires in order to perfect Buyer's first-priority security interest in, and lien on (and right of setoff against), such collateral and any and all proceeds resulting therefrom or from the liquidation thereof. This Section 15.4 applies only to cash collateral and cash equivalent collateral established in accordance with Section 15.3 above.

15.5 Realization Upon Performance Assurance. Upon or at any time after the occurrence and during the continuation of an Event of Default or an Early Termination Date affecting Seller, the Buyer may do any one or more of the following: (i) exercise any of the rights and remedies of a secured party with respect to all Performance Assurance, including any such rights and remedies under law then in effect; (ii) exercise its rights of setoff against any and all property of the Seller in the possession of the Buyer or its agent; (iii) draw on any outstanding letter of credit issued for the Buyer's benefit; and (iv) liquidate all Performance Assurance then held by or for the benefit of the Buyer free from any claim or right of any nature whatsoever of the Seller, including any equity or right of purchase or redemption by the Seller. The Buyer shall apply the proceeds of the collateral realized upon the exercise of any such rights or remedies to reduce the Seller's obligations under this Agreement, subject to the Buyer's obligation to return any surplus proceeds remaining after such obligations are satisfied in full.

15.6 Interest Rate on Cash Collateral. Performance Assurance in the form of cash shall bear interest at the Interest Rate and shall be paid to Seller on the third (3rd) Business Day of each calendar month.

ARTICLE 16
FORCE MAJEURE

16.1 *Force Majeure*.

16.1.1 General. As used in this Agreement, "*force majeure*" or "an event of *force majeure*" means any cause beyond the reasonable control of the Party claiming *force majeure* which, despite the exercise of due diligence, such Party is unable to prevent or overcome. *Force majeure* includes, but is not limited to, acts of God, fire, flood, storms, wars, hostilities, civil strife, strikes and other labor disturbances (even if such strikes or disturbances could be resolved by conceding to the demands of a labor group), earthquakes, fires, lightning, epidemics, sabotage, severe weather, or changes in law or regulation or governmental orders occurring after the Effective Date, to the extent that by the exercise of reasonable foresight such Party could not reasonably have been expected to avoid and by the exercise of due diligence it shall be unable to overcome such *force majeure* event.

16.1.2 Events That Are Not "*Force Majeure*." Notwithstanding Section 16.1.1, the term *force majeure* does not include: (a) Seller's ability to sell, or Buyer's ability to purchase, Net Energy or Environmental Attributes at a more advantageous price than is provided under this Agreement; (b) governmental or regulatory action occurring after receipt of the Commission approval contemplated by Article 27 and Article 28 that impairs Buyer's ability to recover the Contract Price in its rates or that otherwise affects the value of this Agreement to Buyer or (c) the inability for any reason to make payments hereunder when due.

16.1.3 Requirements Upon Occurrence of *Force Majeure*. If either Party is rendered wholly or in part unable to perform its obligations under this Agreement because of an event of *force majeure*, both Parties shall be excused from whatever performance is affected by the event of *force majeure*, provided that:

16.1.3.1 The Party claiming *force majeure* shall, as soon as is reasonably possible after the occurrence of the *force majeure*, give the other Party written notice describing the particulars of the occurrence. If notice is provided by the Party claiming force majeure within seven days of the actual event of *force majeure*, the Party claiming force majeure may identify the start time of the force majeure event and upon the event of *force majeure* being accepted by the notified Party, the party claiming force majeure will be granted relief of obligations under this Agreement from the date identified. If the Party claiming Force Majeure does not provide notification to the other Party within seven days of the event, the Party claiming force majeure will only be eligible to receive relief from obligations within this agreement from the date the notice is provided..

16.1.3.2 The suspension of performance shall be of no greater scope and of no longer duration than is required by the event of *force majeure*.

16.1.3.3 No obligations of either Party which arose before the occurrence causing the suspension of performance and which could and should have been fully performed before such occurrence shall be excused as a result of such occurrence.

16.1.3.4 The Party claiming *force majeure* shall proceed with reasonable diligence to remedy its inability to perform and shall provide weekly progress reports to the other Party describing actions taken to end the *force majeure*.

16.1.3.5 The Party claiming *force majeure* is able to resume performance of its obligations under this Agreement, that Party shall give the other Party written notice to that effect.

Failure of a Party to comply with provisions of Sections 16.1.3.1, 16.1.3.2, 16.1.3.4 and 16.1.3.5 shall create liability of such Party only to the extent the other Party is damaged by such failure.

16.2 Extension of Scheduled Operation Date and the Term. The Scheduled Operation Date shall be extended on a day-for-day basis in the event of *force majeure*. In no event will any delay or failure of performance caused by any conditions or events of *force majeure* extend this Agreement beyond its stated Term.

16.3 Termination for Extended *Force Majeure*. If a delay or failure of performance caused by the event of *force majeure* results in a thirty percent (30%) or more decrease in the delivery or receipt of Net Energy at the Metering Point of the Facility when similarly compared to the most recently provided Annual Forecast preceding the event of *force majeure* and continues for an uninterrupted period of three hundred sixty-five (365) days from the event's occurrence or inception, the Party not claiming *force majeure* may, at any time following the end of such three hundred sixty-five (365) day period, and prior to the event of *force majeure* being cured, terminate this Agreement upon written notice to the party claiming *force majeure*, without further obligation by either Party except as to costs and balances incurred before the effective date of such termination. The Party not claiming *force majeure* may, but shall not be obligated to, extend such three hundred sixty-five (365) day period, for such additional time as it, at its sole discretion, deems appropriate.

ARTICLE 17
FORCED OUTAGE

17.1 Seller to Notify Buyer. Promptly upon the occurrence of an event at the Facility that the Seller deems to be a Forced Outage the Seller shall notify the Buyer of the declared Forced Outage and adjust the forecast if required as specified in Section 8.4.

17.2 Seller to Submit Explanation. Within two (2) Business Days of the Forced Outage event the Seller shall submit to the Buyer a detailed explanation of the Forced Outage event including but not limited to details of the equipment failure, apparent cause of the failure, equipment affected by and taken out of service, estimated lost energy production, and a schedule and plan for making the necessary repairs.

17.3 Buyer Shall Respond to Seller. Upon receipt of the detailed explanation of the Forced Outage event, the Buyer shall within two (2) Business Days respond to the Seller accepting, rejecting or requesting additional information in regards to the declared Forced Outage event. If the Buyer does not respond to the Seller's initial submittal within two (2) Business Days, the declared Forced Outage event shall be deemed to be accepted.

17.4 Adjustment to Seller's Annual Guaranteed Output. Only after the declared Forced Outage event has been accepted by the Buyer and the actual Net Energy reduction of the specific Forced Outage event has been determined to be equal to or greater than 33,000 kWh shall the Seller's Annual Guaranteed Output obligation be adjusted to reflect the Net Energy curtailment that was a result of the Forced Outage. If it is determined that the actual Net Energy reduction associated with the specific Forced Outage event is less that 33,000 kWh, no adjustment of the Seller's Annual Guaranteed Output shall be made.

ARTICLE 18
BUYER'S ACCESS RIGHTS

18.1 Seller to Provide Access. To the extent necessary, Seller hereby grants to the Buyer for the Term of this Agreement all necessary right-of-ways and easements to install, operate, maintain, replace, and remove the Buyer's Metering and Telemetry Equipment, and other equipment and facilities necessary or useful to this Agreement, including adequate and continuing access rights on property of the Seller.

18.2 Indemnity. If the Buyer exercises any right under this Agreement to access or enter upon the Seller's property, such access or entry shall be at the Buyer's sole risk and expense. Buyer shall hold the Seller harmless from, and indemnify the Seller against, any and all liability for any loss, damage or injury to property or persons arising from the Buyer's access to or entry upon to the Seller's property, except to the extent that such loss, damage or injury is cause by the Seller's negligence or willful misconduct.

ARTICLE 19
NO THIRD PARTY LIABILITY,
NO DEDICATION OF FACILITY OR SYSTEM

19.1 No Third Party Liability. Nothing in this Agreement shall be construed to create any duty to, any standard of care with reference to, or any liability to any person not a Party to this Agreement. There are no third party beneficiaries of this Agreement.

19.2 No Dedication. No undertaking by one Party to the other under any provision of this Agreement shall constitute the dedication of that Party's system or facility or any portion thereof to the other Party or to the public or affect the status of the Buyer as an independent public utility corporation or the Seller as an independent entity.

ARTICLE 20
SEVERAL OBLIGATIONS

Except where specifically stated in this Agreement to be otherwise, the duties, obligations and liabilities of the Parties are intended to be several and not joint or collective. Nothing contained in this Agreement shall ever be construed to create an association, trust, partnership or joint venture, or impose a trust or partnership duty, obligation or liability on or with regard to either Party. Each Party shall be individually and severally liable for its own obligations under this Agreement.

ARTICLE 21
WAIVER

Any waiver at any time by either Party of its rights with respect to a default under this Agreement or with respect to any other matters arising in connection with this Agreement shall not be deemed a waiver with respect to any subsequent default or other matter.

ARTICLE 22
CHOICE OF LAW

This Agreement shall be construed and interpreted in accordance with the laws of the State of Idaho without reference to its choice of law provisions.

ARTICLE 23
LIMITATIONS

23.1 Remedies Satisfy Essential Purposes. THE PARTIES CONFIRM THAT THE EXPRESS REMEDIES AND MEASURES OF DAMAGES PROVIDED IN THIS AGREEMENT SATISFY THE ESSENTIAL PURPOSES OF THIS AGREEMENT.

23.2 Sole and Exclusive Remedies. FOR ANY PROVISION FOR WHICH AN EXPRESS REMEDY OR MEASURE OF DAMAGES IS PROVIDED, SUCH EXPRESS REMEDY OR MEASURE OF DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY. THE OBLIGOR'S LIABILITY SHALL BE LIMITED AS SET FORTH IN SUCH PROVISION AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED.

23.3 No Punitive, Consequential or Incidental Damages. IF NO REMEDY OR MEASURE OF DAMAGES IS EXPRESSLY PROVIDED HEREIN, THE OBLIGOR'S LIABILITY SHALL BE LIMITED TO DIRECT ACTUAL DAMAGES ONLY, SUCH DIRECT ACTUAL DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. UNLESS EXPRESSLY HEREIN PROVIDED, NEITHER PARTY SHALL BE LIABLE FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, BY STATUTE, IN TORT OR CONTRACT, UNDER ANY INDEMNITY PROVISION OR OTHERWISE. IT IS THE INTENT OF THE PARTIES THAT THE LIMITATIONS IMPOSED IN THIS AGREEMENT ON REMEDIES AND THE MEASURE OF DAMAGES BE WITHOUT REGARD TO THE CAUSE OR CAUSES RELATED THERETO, INCLUDING THE NEGLIGENCE OF ANY PARTY, WHETHER SUCH NEGLIGENCE BE SOLE, JOINT OR CONCURRENT, OR ACTIVE OR PASSIVE.

23.4 Liquidated Damages. TO THE EXTENT ANY DAMAGES REQUIRED TO BE PAID HEREUNDER ARE LIQUIDATED, THE PARTIES ACKNOWLEDGE THAT THE DAMAGES ARE DIFFICULT OR IMPOSSIBLE TO DETERMINE, OR OTHERWISE OBTAINING AN ADEQUATE REMEDY IS INCONVENIENT AND THE DAMAGES CALCULATED HEREUNDER CONSTITUTE A REASONABLE APPROXIMATION OF THE HARM OR LOSS.

ARTICLE 24
DISPUTES

24.1 Disputes. If a dispute arises under this Agreement (a "Dispute"), within ten (10) days following the delivered date of a written request by either Party (a "Dispute Notice"), (1) each Party shall appoint a representative, and (2) the Parties' representatives shall meet, negotiate and attempt in good faith to resolve the Dispute quickly, informally and inexpensively. If the Parties' representatives cannot resolve the Dispute within thirty (30) days after commencement of negotiations, then within ten (10) Business Days following any request by either Party at any time thereafter, each Party representative (3) shall independently prepare a written summary of the Dispute describing the issues and claims, (4) shall exchange its summary with the summary of the Dispute prepared by the other Party representative, and (5) shall submit a copy of both summaries to a senior officer of the representative's Party with authority to irrevocably bind the Party to a resolution of the Dispute. Within ten (10) Business Days after receipt of the Dispute summaries, the senior officers for both Parties shall negotiate in good faith to resolve the

Dispute. If the Parties are unable to resolve the Dispute within fourteen (14) Business Days following receipt of the Dispute summaries by the senior offices, either Party may seek available remedies.

24.2 Venue. Venue for any litigation arising out of or related to this Agreement shall lie in the District Court of the Fourth Judicial District of Idaho in and for the County of Ada.

ARTICLE 25
EVENTS OF DEFAULT, DELAY DAMAGES AND MATERIAL BREACHES

25.1 Events of Default. The following shall be deemed to be Events of Default:

25.1.1 A Party's dissolution or liquidation;

25.1.2 A Party's assignment of this Agreement or any of its rights under this Agreement for the benefit of creditors (except for an assignment to the Facility Lender as security under the Financing Documents as permitted by this Agreement).

25.1.3 A Party's filing of a petition in bankruptcy or insolvency or for reorganization or arrangement under the bankruptcy laws of the United States or under any insolvency act of any state, or a Party voluntarily taking advantage of any such law or act by answer or otherwise.

25.1.4 The filing of a case in bankruptcy or any proceeding under any other insolvency law against a Party that could materially impact Buyer's ability to perform its obligations under this Agreement if the affected Party does not obtain a stay or dismissal of the filing within sixty (60) days after the Party receives a notice of default.

25.1.5 A Party's assignment of this Agreement, except as permitted by this Agreement.

25.1.6 Any representation or warranty made by a Party in this Agreement proves to have been false or misleading in any material respect when made or ceases to remain true during the Term if such inaccuracy or cessation would reasonably be expected to result in a significant adverse impact on the other Party and such default is not cured within thirty (30) days after the Party's receipt of a notice of default.

25.1.7 Seller's failure to establish and maintain Performance Assurance as required by this Agreement if the failure is not cured within thirty (30) days of Seller's receipt of a notice of default.

25.1.8 A Guaranty Default affecting a Guaranty delivered in support of this Agreement if the Guaranty Default is not cured within the time permitted by the Guaranty and the Seller does not provide substitute Performance Assurance to replace the Guaranty within fifteen (15) Business Days after the Seller's receipt of a notice of the Guaranty Default.

25.1.9 Seller's unexcused failure to deliver energy from the Facility to Buyer as required under this Agreement if the failure is not cured within fifteen (15) Business Days of Seller's receipt of a notice of default.

25.1.10 Buyer's unexcused failure to receive and accept energy from the Facility as required under this Agreement if the failure is not cured within fifteen (15) days of Buyer's receipt of a notice of default.

25.1.11 Seller's failure to attain an actual Operation Date within 2,904 hours (4 months) of the Scheduled Operation Date.

25.1.12 A Party's failure to make a payment to the other Party when due under this Agreement, if the failure is not cured within ten (10) Business Days of the Party's receipt of a notice of default.

25.1.13 A Party's failure to comply with any material obligation under this Agreement, if the failure would result in a significant adverse impact on the other Party (other than a default already specifically enumerated in this Article) and the failure is not cured within thirty (30) days of the Party's receipt of a notice of default; *provided, however,* if such default cannot be cured within thirty (30) days despite Seller's diligent efforts but Seller commences the cure within the thirty (30) day period and thereafter diligently pursues the cure, the thirty (30) day period shall be extended for as long as is reasonably required to cure the default (but in no event more than a total of one hundred twenty (120) days.

25.1.14 Seller's failure to meet the requirements of any one of the Project Milestones identified in Appendix H.

25.2 Notice of Default. If either Party defaults in its performance of this Agreement as provided in Section 25.1, the non-defaulting Party may give notice of the default in writing to the defaulting Party, specifying in reasonable detail the nature of the default. If the defaulting Party fails to cure the default within sixty (60) days or any other cure period specifically identified for the default, the non-defaulting Party may exercise the specific remedies identified for that default or if no specifics are identified, at its option, terminate this Agreement and/or pursue its legal or equitable remedies, subject to any limitation on remedies and damages set forth in this Agreement. The non-defaulting Party has the right, but not the obligation, to extend the cure period if the non-defaulting Party determines that the defaulting Party is using all commercially reasonable efforts to cure the default but is unable to cure the default within an initial sixty (60) day cure period or the specific cure period for the identified default.

25.3 Material Breaches. The notice and cure provisions in Article 25 do not apply to defaults identified in this Agreement as Material Breaches. Material Breaches must be cured as expeditiously as possible following occurrence of the breach and once cured shall no longer be cause for termination under this Agreement.

25.4 Delay Damages. If Seller fails to achieve the Operation Date within thirty (30) days after the Scheduled Operation Date and such failure is not excused by *force majeure* or Forced Outage by the Seller or by default or delay of Buyer Delay Liquidated Damages will be calculated as defined in Section 1.13 of this agreement. Buyer shall calculate and invoice the Seller and the Seller shall pay Buyer for any Delay Liquidated Damages accrued during a given calendar month within fifteen (15) days of the receipt of the Buyer's invoice. The calculation and payment of Delay Damages to the Buyer from the Seller shall not exceed $690,000.

25.5 Limitations on Seller's Damages. The following limits shall apply to Seller's liability for damages: (a) Seller's aggregate financial liability to the Buyer in the event this Agreement is terminated as allowed in Section 26.5.2 shall be limited to any Performance Assurances the Seller has been required to provide as specified within this Agreement as of the date of the termination, (b) Seller's aggregate financial liability to Buyer for Delay Damages shall not exceed the amount specified in Section 25.4, (c) Seller's aggregate financial liability for Net Energy Shortfall Damages for any single Contract Year shall not exceed the values as specified in Appendix D. The limitations on damages set forth in this Section 25.5 shall not apply to damages arising out of either of the following events:

25.5.1 Willful breach of this Agreement by Seller.

25.5.2 Any claim for indemnification under Article 14.

25.6 Duty to Mitigate Damages. Each Party agrees that it has a duty to mitigate damages and covenants that it will use commercially reasonable efforts to minimize any damages it may incur as a result of the other Party's performance or non-performance of the Agreement.

25.7 Buyer's right to collect damages and any other unpaid amounts. The Buyer shall have the right to withhold any past due, undisputed payments payable to the Buyer from any payments payable to the Seller.

ARTICLE 26
TERMINATION

26.1 Termination. Upon execution, this Agreement shall continue in full force and effect for the Term unless terminated in accordance with this Article.

26.2 Mutual Agreement. The Parties can mutually terminate this Agreement by a writing signed by both Parties.

26.3 Event of Default. A non-defaulting Party may terminate this Agreement in accordance with Article 25.

26.4 Prolonged *Force Majeure*. A Party not claiming *force majeure* may terminate this Agreement in accordance with Section 16.3.

26.5 Right to Terminate.

26.5.1 If the Commission issues a final order either disapproving this Agreement or approving it with condition(s) or modification(s) unacceptable to the Party or Parties adversely affected by such modification(s) or condition(s), either Party has the right to terminate this Agreement by written notice to the other Party either within ten (10) Business Days after the Commission denies any Petition(s) for Reconsideration or, if the Commission grants reconsideration, within ten (10) Business Days after the Commission renders a decision on reconsideration if said decision either disapproves the Agreement or approves it with condition(s) or modification(s) unacceptable to either Party. Any such termination under this Section shall be effective ten (10) Business Days after such notice is given.

26.5.2 Either Party may terminate this Agreement as specified in Article 3 of this Agreement or if after commercially reasonable efforts the Seller is unable to satisfy the fourth Project Milestone (issuance of power plant notice to proceed). If termination occurs as a result of a default of the fourth Project Milestone and the Seller is able to demonstrate to the Buyer's reasonable satisfaction that the uncured default was a result of unforeseen Facility financing costs or construction costs, the Seller's Performance Assurance shall be released and no damages to Buyer will be applicable.

26.5.3 If a Party does not give the other Party a notice of termination in accordance with this Section 26.5 on or before the applicable date specified above, the affected termination right under this Section 26.5 shall be deemed waived and this Agreement shall remain in full force and effect in accordance with its terms regardless of any subsequent Commission order.

26.5.4 Neither Party shall have any liability to the other Party for any termination under this Section 26.5.

26.5.5 Any termination under this Section shall be effective ten (10) Business Days after such notice is given.

26.5.6 If termination of this Agreement is due to a default or Material Breach of this Agreement by the Seller neither the Seller, nor the Facility Lender or Investor individually or collectively taking title to the Facility by foreclosure or otherwise shall make any arrangements with any party other than the Buyer for the sale of electric energy generated from geothermal energy from this Site and the associated Neal Hot Springs geothermal reservoir for a period of three (3) years from the date of the termination. If after termination and within this three (3) year period, the Seller wishes to resume operations of this Facility and prior to the Facility resuming operations; 1) all applicable damages due the Buyer as a result of the termination shall have been satisfied, and 2) a purchased power agreement for the sale of energy from this Facility to the Buyer shall be completed. The parties shall act in good faith to negotiate a new purchase power agreement. The new purchase power agreement shall include terms and conditions similar to this agreement, except for revisions required to update this agreement to current industry standards and revisions required to address the termination of the prior Agreement. Unless mutually agreed to, the energy pricing in this new purchase power agreement shall be equal to the energy pricing contained within the Agreement.

ARTICLE 27
GOVERNMENTAL AUTHORIZATION

This Agreement is subject to the jurisdiction of those governmental agencies having control over either Party of this Agreement, including, but not limited to, the Commission.

ARTICLE 28
REGULATORY APPROVAL

28.1 Within ten (10) Business Days after the Effective Date Buyer shall file this Agreement with the Commission, seeking Commission Approval.

ARTICLE 29
SUCCESSORS AND ASSIGNS

29.1 Binding Agreement. This Agreement and all of the terms and provisions of this Agreement shall be binding upon and inure to the benefit of the respective permitted successors and assigns of the Parties.

29.2 Assignment without Consent. Except as permitted in this Article, neither Party shall assign this Agreement or any portion of this Agreement, without the prior written consent of the other Party, which consent shall not be unreasonably withheld, conditioned or delayed.

29.3 Seller's Consent Not Required. Seller's consent shall not be required for Buyer to assign this Agreement to an Affiliate of the Buyer, provided that (1) the assignee has the same or better credit rating from Moody's and S&P as the Buyer and (2) the assignee's non-credit enhanced unsecured debt (a) has a rating by at least one of the two rating agencies, and (b) does not have a Credit Rating below BBB- by S&P or below Baa3 by Moody's, or does not have a Credit Rating of BBB– by S&P accompanied by a negative watch or Baa3 by Moody's accompanied by a negative watch. If S&P changes its rating system during the Term, "BBB-" shall be replaced by S&P's lowest investment grade rating under the new rating system; likewise, if Moody's changes its rating system during the Term, "Baa3" shall be replaced by Moody's lowest investment grade rating under the new rating system.

29.4 Buyer's Consent Not Required. Buyer's consent shall not be required:

29.4.1 For Seller to assign this Agreement for collateral purposes to the Facility Lender; or

29.4.2 For Seller to assign this Agreement to any Affiliate of the Seller, provided that the assignee provide the Performance Assurance of the Agreement; or

29.4.3 For Seller to Assign this Agreement to any third party or parties in connection with a sale of the Facility to such third party or parties, provided that such third party or parties shall either: (1) have at least three (3) years experience in operating geothermal electric generating facilities with an installed nameplate capacity of ten thousand (10,000) kW or greater; or (2) enter into an operating agreement with another person (who may be the Seller or an Affiliate of the Seller) who has at least three (3) year's experience in operating geothermal electric generating facilities with an installed nameplate capacity of ten thousand (10,000) kW or greater; and (3) the third party or parties shall provide the Performance Assurance of the Agreement.

29.5 Accommodation of Facility Lender or Investor. To facilitate the Seller's obtaining of Project Financing or to facilitate investments in the Seller, Buyer shall use commercially reasonable efforts to provide such consents to assignments, certifications, representations, information, opinions or other documents as may be reasonably requested by the Seller, the Facility Lender or the Investor in connection with the financing of or investment in the Facility; provided that in responding to any such request, the Buyer shall have no obligation to provide any consent, or enter into any agreement that in Buyer's reasonable opinion significantly adversely affects or expands any of the Buyer's rights, benefits, risks and/or obligations under this Agreement. Seller shall reimburse, or shall cause the Facility Lender or the Investor to reimburse, the Buyer for the incremental direct expenses (including, without limitation, the reasonable fees and expenses of counsel) incurred by the Buyer in the preparation, negotiation, execution and/or delivery of any documents requested by the Seller, Facility Lender or Investor, and provided by the Buyer, pursuant to this Article. The rights of the Facility Lender or Investor will be set forth in a collateral assignment, estoppel agreement, consent agreement or similar instrument delivered at the closing of any Facility financing or any investment and will include the following provisions:

29.5.1 Right to Cure Defaults. Facility Lender or Investor shall have the right, but not the obligation, to perform any act required to be performed by the Seller under this Agreement to prevent or cure a default by the Seller, and such act performed by Facility Lender or Investor shall be as effective to prevent or cure a default as if done by the Seller. Seller shall, in accordance with Article 32, provide the Buyer with a notice identifying the agent or trustee of the Facility Lender or the Investor and providing appropriate contact information for the Facility Lender or Investor. Following receipt of such notice, Buyer shall provide copies of any notices provided to Seller concerning any default or Event of Default described in this Agreement to the agent or trustee of the Facility Lender or Investor specified by the Seller in accordance with Article 32, and the Buyer will accept a cure performed by the agent or trustee of the Facility Lender or

Investor and will negotiate in good faith with the agent or trustee of the Facility Lender and Investor as to the cure period(s) that will be allowed for the Facility Lender or Investor to cure any default or Event of Default hereunder and the Buyer will accept a cure performed by the Facility Lender or Investor, so long as the cure is accomplished within the applicable cure period so agreed to by the Buyer and the Facility Lender or Investor. In complying with the notice provisions in this Section 29.5.1, Buyer will have the right to rely on the information provided by the Seller in accordance with Article 32.

29.5.2 Right to Assume Agreement. If the Seller defaults under any financing or investment documents, the Facility Lender or Investor may (but shall not be obligated to) assume, or cause its designee to assume, all of the interests, rights, and obligations of the Seller thereafter arising under this Agreement. Notwithstanding any such assumption, the Seller shall not be released or discharged from and shall remain liable for any and all obligations to the Buyer arising or accruing under this Agreement.

29.5.3 No Obligation to Perform. Buyer agrees that neither the Facility Lender nor the Investor shall be obligated to perform any obligation or be deemed to incur any liability or obligation provided in this Agreement on the part of the Seller or shall have any obligation or liability to the Buyer with respect to this Agreement except to the extent the Facility Lender or Investor has assumed the obligations of the Seller under this Agreement pursuant to this Article; *provided that* the Buyer shall nevertheless be entitled to exercise all of its rights under this Agreement against the Seller in the event that the Seller, Facility Lender or Investor fails to perform the Seller's obligations under this Agreement.

29.5.4 Notice of Facility Lender or Investor Action. Within ten (10) Business Days following the Seller's receipt of each written notice from a Facility Lender or an Investor of a default, or of Facility Lender's or Investor's intent to exercise any remedies, under the Financing Documents or any investment agreement, Seller shall deliver a copy of such notice to the Buyer.

29.5.5 If the Facility Lender or Investor directly or indirectly, takes possession of or title to the Facility (including possession by a receiver or title by foreclosure or deed in lieu of foreclosure), then the Facility Lender or Investor shall assume all of the Seller's obligations under this Agreement. *Provided that* the Facility Lender or Investor shall have no personal liability for any monetary obligations of Seller under this Agreement which are due and owing to Buyer as of the assumption date.

29.5.6 If the Facility Lender or Investor elect to sell or transfer the Facility (after directly or indirectly taking possession of, or title to, the Facility) or if the sale of the Facility occurs through the actions of the Facility Lender or Investor (including, a foreclosure sale where a third party is the buyer, or otherwise), then, as a condition of such sale or transfer, the Facility Lender or Investor shall cause the buyer or transferee of the Facility to assume all of Seller's obligations arising under this Agreement from and after the date of such sale or transfer.

29.6 Subcontracting. Seller may subcontract its duties or obligations under this Agreement without the prior written consent of the Buyer, provided, that no such subcontract shall relieve the Seller of any of its duties or obligations under this Agreement.

29.7 Right of First Offer upon Sale of Facility Assets, increase of existing Facility Nameplate rating, or addition of new generation capacity.

29.7.1 Facility Assets. If, at any time during the Term, Seller intends to sell the assets comprising all or substantially all of the Facility (the "Facility Assets") to a person or entity that is not an Affiliate of Seller, Seller shall first offer the Facility Assets to Buyer. Seller's offer to the Buyer shall set forth, in writing and in reasonable detail, substantially similar terms and conditions of the offer being proposed by the Seller to the other person or entity. Seller shall promptly answer any questions that Buyer may have concerning the offered terms and conditions and shall meet with Buyer to discuss the offer.

29.7.2 Buyer's Rejection of Offer; Revival of Offer. If Buyer does not provide notice of its intent to accept the offered terms and conditions within thirty (30) days after receiving each of the Seller's offers made under 29.7.1, Seller may in its sole discretion enter into an agreement to sell the Facility Assets to a third party in compliance with the requirements of this Article 29 and on terms and conditions satisfactory to Seller in its sole discretion. Seller may elect not to proceed with the sale of the Facility Assets.

29.7.3 Buyer's Acceptance of Offer. If Buyer provides notice of its intent to accept the offer made by Seller under this Section, the Parties shall negotiate in good faith to enter into a definitive sales agreement that incorporates the terms and conditions of Seller's offer. The definitive agreement shall be subject to each Party's management and regulatory approvals. If within thirty (30) days of Buyer's acceptance of the offer, a written term sheet setting forth the major terms of the definitive sales agreement, including a timeline to complete negotiations of the definitive sales agreement, has not been executed by an officer of the Buyer and Seller, then either Party may terminate the negotiations without further obligation to the other Party.

29.7.4 Limit on Right of First Offer. The right of first offer set forth in this Section shall apply only if Seller sells all or substantially all of the assets comprising the Facility in an asset sale to a third party. It shall not apply to changes in the membership of Seller or any other reorganization, change of control or other transaction directly or indirectly affecting Seller or an Affiliate of Seller.

29.7.5 Right of First Offer of additional geothermal generation. If at the time of development of this Facility or at any future date, the Seller proposes to increase the nameplate rating of this Facility or add additional geothermal electrical generation at this Site or in close proximity to this Site, the Seller shall first offer the additional geothermal electrical generation to the Buyer as an amendment to this Agreement, as a separately negotiated purchase power agreement, or whole or partial ownership of the Facility or the additional generation facilities. This offer from the Seller shall include but not be limited to proposed capacity, energy pricing, contract term, online date and other information that will enable the Buyer to be able to evaluate the Buyer's interest in this additional geothermal electrical generation. Upon receipt of the Seller's offer (containing adequate information) the Buyer shall have sixty (60) days to respond to Seller's offer of the Buyer's intent to continue negotiations for this additional geothermal electrical generation. If the Buyer provides notice that the Buyer has no current intention to continue negotiations the Seller may pursue other opportunities with other parties for the development and sale of this additional geothermal electrical generation. If the Buyer provides notice to the Seller of the desire to continue negotiations the Buyer and Seller shall commence good faith negotiations of an amendment to this Agreement and/or a separate agreement. If after one hundred and twenty (120) days of good faith negotiations, an agreement is not completed and/or appears to not be imminent, the Seller may provide notice to the Buyer of their intention to pursue opportunities with other parties. By mutual consent, this one hundred twenty (120) day negotiation period may be extended.

ARTICLE 30
MODIFICATION

No modification to this Agreement shall be valid unless it is in writing and signed by both Parties and subsequently approved by the Commission.

ARTICLE 31
TAXES

Each Party shall pay before delinquency all taxes and other governmental charges which, if failed to be paid when due, could result in a lien upon the Facility or the Interconnection Facilities.

ARTICLE 32
NOTICES

All written notices under this Agreement shall be directed as follows and shall be considered delivered when faxed, e-mailed and confirmed with deposit in the U.S. Mail, first-class, postage prepaid, as follows:

To Seller:

USG Oregon LLC
Attn: Manager
1505 Tyrell Lane
Boise, ID 83706
Phone: 208-424-1027
Fax: 208-424-1030
Email: dkunz@usgeothermal.com

with a copy to: USG Oregon LLC
Attn: CFO
1505 Tyrell Lane
Boise, ID 83706
Phone: 208-424-1027
Fax: 208-424-1030
Email: khawkley@usgeothermal.com

Facility Lender or Investor: To be identified by the Seller when applicable. The Seller shall be limited to identify only one Facility Lender or Investor.

To Buyer: Idaho Power Company
Attn: Senior Vice President, Power Supply
P.O. Box 70
Boise, ID 83707
Fax: 208-388-6936
Email: lgrow@idahopower.com

with a copy to: Idaho Power Company
Attn: Legal Department
P.O. Box 70
Boise, ID 83707
Fax: 208-388-6936
Email: bkline@idahopower.com

By giving notice to the other Party, either Party may from time to time change the address (es) to which notices or copies are to be sent to it under this Agreement.

ARTICLE 33
ADDITIONAL TERMS AND CONDITIONS

This Agreement includes the following appendices, which are attached hereto and included by reference:

Appendix A	Contract Prices
Appendix B	Facility Description
Appendix C	Sample Form of Seller Guaranty
Appendix D	Net Energy Shortfall Price and Annual Cap
Appendix E	Engineering Certificates
Appendix F	Communications
Appendix G	One-Line Diagram
Appendix H	Project Milestones

ARTICLE 34
SEVERABILITY

The invalidity or unenforceability of any term or provision of this Agreement shall not affect the validity or enforceability of any other terms or provisions and this Agreement shall be construed in all other respects as if the invalid or unenforceable term or provision were omitted, unless the deletion of such provision or provisions would result in such a material change so as to cause completion of the transactions contemplated herein to be unreasonable.

ARTICLE 35
CONFIDENTIAL BUSINESS INFORMATION

35.1 Definition. The following constitutes "Confidential Business Information," whether oral or written: (1) Parties' proposals and negotiations before the Effective Date concerning this Agreement, and (2) information that a Party stamps or otherwise identifies as "confidential" or "proprietary" before disclosing it to the other Party. Notwithstanding the foregoing, "Confidential Business Information" does not include (A) information that was publicly available at the time of the disclosure thereof by one Party to the other, other than as a result of a disclosure by the receiving Party in breach of this Article; (B) information that becomes publicly available through no fault of the receiving Party after the time of the disclosure by the disclosing Party to the receiving Party; (C) information that was rightfully in the possession of the receiving Party (without confidential or proprietary restriction) at the time of disclosure or that becomes available to the receiving Party from a source not subject to any restriction against disclosing such information to the receiving Party; and (D) information that the receiving Party independently developed without a violation of this Agreement. The Confidential Business Information specified in item (1) above shall be considered the Confidential Business Information of both Seller and Buyer and, therefore, exceptions (C) and (D) above shall not apply to such information.

35.2 Duty to Maintain Confidentiality. Each Party agrees not to disclose Confidential Business Information of the other Party to any other person (other than its Affiliates, counsel, consultants, lenders, prospective lenders, purchasers, investors, contractors constructing or providing services to the Facility (including but not limited to turbine suppliers), employees, officers and directors who agree to be bound by the provisions of this Article), without the prior written consent of the other Party, provided that either Party may disclose Confidential Business Information if and to the extent such disclosure is required (1) by any Requirements of Law, (2) in order for the Buyer to receive regulatory recovery of expenses related to the Agreement, (3) pursuant to an order of a court or regulatory agency or (4) in order to enforce this Agreement or to seek approval of this Agreement. In addition, Seller may include information concerning the terms or conditions of this Agreement in financial statements to the extent that such information is required to be included in financial statements prepared with respect to the

Facility, Seller or any Affiliate of the Seller in accordance with generally accepted accounting principles consistently applied. In the event a Party is required by Requirements of Law or by a court or regulatory agency to disclose Confidential Business Information, such Party shall to the extent possible notify the other Party at least three (3) Business Days in advance of such disclosure and the other Party may seek an appropriate protective order or waive compliance with the confidentiality terms of this Agreement. In that event, the Party required by Requirements of Law or by a court or regulatory agency to disclose Confidential Business Information will cooperate fully with the other Party in seeking a protective order or other assurance that confidential treatment will be accorded to the Confidential Business Information.

35.3 Irreparable Injury; Remedies. Each Party agrees that violation of the terms of this Article constitutes irreparable harm to the other, and that the harmed Party may seek any and all remedies available to it at law or in equity, including but not limited to injunctive relief.

ARTICLE 36
REPRESENTATIONS AND WARRANTIES

36.1 Seller's Representations, Warranties and Covenants. Seller hereby represents and warrants as follows:

36.1.1 Seller is a Delaware Limited Liability company, organized and existing under the laws of the State of Delaware with a principal place of business at 1505 Tyrell Lane, Boise, ID 83706. Seller is qualified to do business in each other jurisdiction where the failure to so qualify would have a material adverse effect on the business or financial condition of the Seller; and the Seller has all requisite power and authority to conduct its business, to own its properties, and to execute, deliver, and perform its obligations under this Agreement.

36.1.2 The execution, delivery, and performance of its obligations under this Agreement by the Seller have been duly authorized by all necessary business entity action(s), and do not and will not:

36.1.2.1 Require any consent or approval by any governing body of the Seller, other than that which has been obtained and is in full force and effect (evidence of which shall be delivered to the Buyer upon its request);

36.1.2.2 violate any provision of law, rule, regulation, order, writ, judgment, injunction, decree, determination, or award currently in effect having applicability to the Seller or violate any provision in any formation documents of the Seller, the violation of which could have a material adverse effect on the ability of the Seller to perform its obligations under this Agreement;

36.1.2.3 result in a breach or constitute a default under the Seller's formation documents or bylaws, or under any agreement relating to the management or affairs of the Seller or any indenture or loan or credit agreement, or any other agreement, lease, or instrument to which the Seller is a party or by which the Seller or its properties or assets may be bound or affected, the breach or default of which could reasonably be expected to have a material adverse effect on the ability of the Seller to perform its obligations under this Agreement; or

36.1.2.4 result in, or require the creation or imposition of any mortgage, deed of trust, pledge, lien, security interest, or other charge or encumbrance of any nature (other than as may be contemplated by this Agreement) upon or with respect to any of the assets or properties of the Seller now owned or hereafter acquired, the creation or imposition of which could reasonably be expected to have a material adverse effect on the ability of the Seller to perform its obligations under this Agreement.

36.1.3 This Agreement is a valid and binding obligation of the Seller.

36.1.4 The execution and performance of this Agreement will not conflict with or constitute a breach or default under any contract or agreement of any kind to which the Seller is a party or any judgment, order, statute, or regulation that is applicable to the Seller or the Facility.

36.2 Seller's Disclaimer of Certain Representations and Warranties. NOTWITHSTANDING ANY OTHER PROVISION OF THIS AGREEMENT,

36.2.1 SELLER DISCLAIMS ALL WARRANTIES OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE WITH RESPECT TO THE SALE OF TEST ENERGY, NET ENERGY AND ENVIRONMENTAL ATTRIBUTES.

36.2.2 SELLER MAKES NO REPRESENTATION OR WARRANTY, EITHER EXPRESS OR IMPLIED, REGARDING THE CURRENT OR FUTURE EXISTENCE OF ANY ENVIRONMENTAL ATTRIBUTES UNDER THIS AGREEMENT OR OTHERWISE OR THEIR CHARACTERIZATION OR TREATMENT UNDER APPLICABLE LAW OR OTHERWISE.

36.3 Buyer's Representations, Warranties and Covenants. Buyer hereby represents and warrants as follows:

36.3.1 Buyer is a corporation duly organized, validly existing and in good standing under the laws of the State of Idaho and is qualified in each other jurisdiction where the failure to so qualify would have a material adverse effect upon the business or financial condition of the Buyer; and the Buyer has all requisite power and authority to conduct its business, to own its properties, and to execute, deliver, and perform its obligations under this Agreement.

36.3.2 The execution, delivery, and performance of its obligations under this Agreement by the Buyer has been duly authorized by all necessary corporate action.

36.3.2.1 violate any provision of law, rule, regulation, order, writ, judgment, injunction, decree, determination, or award currently in effect having applicability to the Buyer or violate any provision in any corporate documents of the Buyer, the violation of which could have a material adverse effect on the ability of the Buyer to perform its obligations under this Agreement;

36.3.2.2 result in a breach or constitute a default under the Buyer's corporate charter or bylaws, or under any agreement relating to the management or affairs of the Buyer, or any indenture or loan or credit agreement, or any other agreement, lease, or instrument to which the Buyer is a party or by which the Buyer or its properties or assets may be bound or affected, the breach or default of which could reasonably be expected to have a material adverse effect on the ability of the Buyer to perform its obligations under this Agreement; or

36.3.2.3 result in, or require the creation or imposition of any mortgage, deed of trust, pledge, lien, security interest, or other charge or encumbrance of any nature (other than as may be contemplated by this Agreement) upon or with respect to any of the assets or properties of the Buyer now owned or hereafter acquired, the creation or imposition of which could reasonably be expected to have a material adverse effect on the ability of the Buyer to perform its obligations under this Agreement.

36.3.3 Subject to Commission Approval, this Agreement is a valid and binding obligation of the Buyer.

36.3.4 The execution and performance of this Agreement will not conflict with or constitute a breach or default under any contract or agreement of any kind to which the Buyer is a party or any judgment, order, statute, or regulation that is applicable to the Buyer.

36.3.5 Except for Commission Approval, to the best knowledge of the Buyer, all approvals, authorizations, consents, or other action required by any Governmental Authority to authorize the Buyer's execution, delivery and performance of this Agreement have been duly obtained and are in full force and effect.

ARTICLE 37
ENTIRE AGREEMENT

This Agreement constitutes the entire Agreement of the Parties concerning the subject matter of this Agreement and supersedes all prior or contemporaneous oral or written agreements between the Parties concerning the subject matter of this Agreement. No oral or written representation, warranty, course of dealing or trade usage not contained or referenced herein shall be binding on either Party.

ARTICLE 38
COUNTERPARTS

This Agreement may be executed by the Parties in two or more separate counterparts (including by facsimile transmission), each of which shall be deemed an original, and all of said counterparts taken together shall be deemed to constitute one and the same instrument.

ARTICLE 39
CAPTIONS

The captions for Articles and Sections contained in this Agreement are for convenience and reference only and in no way define, describe, extend or limit the scope of this Agreement or the intent of any provision contained herein.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed in their respective names on the dates set forth below:

USG Oregon LLC	**IDAHO POWER COMPANY**
By	By Lisa A. Grow
Daniel Kunz	Lisa A. Grow
Printed Name	Printed Name
Manager – USG Oregon LLC	Senior Vice President, Power Supply
12/11/2009	12·11·09
Date	Date

APPENDIX A

TO

POWER PURCHASE AGREEMENT

BETWEEN

USG OREGON LLC

AND

IDAHO POWER COMPANY

CONTRACT PRICES ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2012	96.00	96.00	70.37	70.37	70.37	96.00	115.20	115.20	96.00	96.00	115.20	115.20
2013	99.00	99.00	72.57	72.57	72.57	99.00	118.80	118.80	99.00	99.00	118.80	118.80
2014	102.78	102.78	75.34	75.34	75.34	102.78	123.34	123.34	102.78	102.78	123.34	123.34
2015	106.79	106.79	78.28	78.28	78.28	106.79	128.15	128.15	106.79	106.79	128.15	128.15
2016	109.27	109.27	80.09	80.09	80.09	109.27	131.12	131.12	109.27	109.27	131.12	131.12
2017	111.83	111.83	81.97	81.97	81.97	111.83	134.20	134.20	111.83	111.83	134.20	134.20
2018	114.49	114.49	83.92	83.92	83.92	114.49	137.38	137.38	114.49	114.49	137.38	137.38
2019	116.45	116.45	85.36	85.36	85.36	116.45	139.74	139.74	116.45	116.45	139.74	139.74

2020	118.46	118.46	86.83	86.83	86.83	118.46	142.15	142.15	118.46	118.46	142.15	142.15
2021	120.52	120.52	88.34	88.34	88.34	120.52	144.62	144.62	120.52	120.52	144.62	144.62
2022	122.63	122.63	89.89	89.89	89.89	122.63	147.16	147.16	122.63	122.63	147.16	147.16
2023	124.37	124.37	91.16	91.16	91.16	124.37	149.24	149.24	124.37	124.37	149.24	149.24
2024	126.13	126.13	92.46	92.46	92.46	126.13	151.36	151.36	126.13	126.13	151.36	151.36
2025	127.94	127.94	93.78	93.78	93.78	127.94	153.52	153.52	127.94	127.94	153.52	153.52
2026	129.77	129.77	95.12	95.12	95.12	129.77	155.73	155.73	129.77	129.77	155.73	155.73
2027	131.65	131.65	96.50	96.50	96.50	131.65	157.98	157.98	131.65	131.65	157.98	157.98
2028	132.92	132.92	97.43	97.43	97.43	132.92	159.51	159.51	132.92	132.92	159.51	159.51
2029	134.21	134.21	98.38	98.38	98.38	134.21	161.05	161.05	134.21	134.21	161.05	161.05
2030	135.52	135.52	99.33	99.33	99.33	135.52	162.62	162.62	135.52	135.52	162.62	162.62
2031	136.84	136.84	100.30	100.30	100.30	136.84	164.21	164.21	136.84	136.84	164.21	164.21
2032	138.18	138.18	101.29	101.29	101.29	138.18	165.82	165.82	138.18	138.18	165.82	165.82
2033	139.54	139.54	102.28	102.28	102.28	139.54	167.45	167.45	139.54	139.54	167.45	167.45
2034	140.92	140.92	103.29	103.29	103.29	140.92	169.10	169.10	140.92	140.92	169.10	169.10
2035	142.31	142.31	104.32	104.32	104.32	142.31	170.78	170.78	142.31	142.31	170.78	170.78
2036	143.73	143.73	105.35	105.35	105.35	143.73	172.47	172.47	143.73	143.73	172.47	172.47

APPENDIX B

TO

POWER PURCHASE AGREEMENT

BETWEEN

USG OREGON LLC

AND

IDAHO POWER COMPANY

FACILITY DESCRIPTION

B-1 DESCRIPTION OF FACILITY

The Facility is the Neal Hot Springs Unit #1 geothermal power plant.

The Buyer shall update this Description of Facility to be consistent with the Buyers Facility description contained within the Buyers notice to proceed to the primary contractor responsible for the construction of the Neal Hot Springs Geothermal Power Plant within sixty (60) days of the date the Seller issues this notice to proceed. The revised Description of Facility must include specific generation and geothermal plant information. Including but not limited to generation unit nameplate ratings, VAR capability, approximated geothermal production and injection well configuration, geothermal fluid delivery and handling system and any other information deemed to be appropriate to specifically identify the Facility subject to the terms and conditions of this Agreement.

As of the Effective Date of this Agreement the Description of the Facility is as follows:

Summary Description of Facility:
The Facility will be comprised of two or three modular power plant units provided by Turbine Air Systems. The units will be air cooled. Geothermal fluid will be produced from two or more production wells and injected back via two or more injection wells.

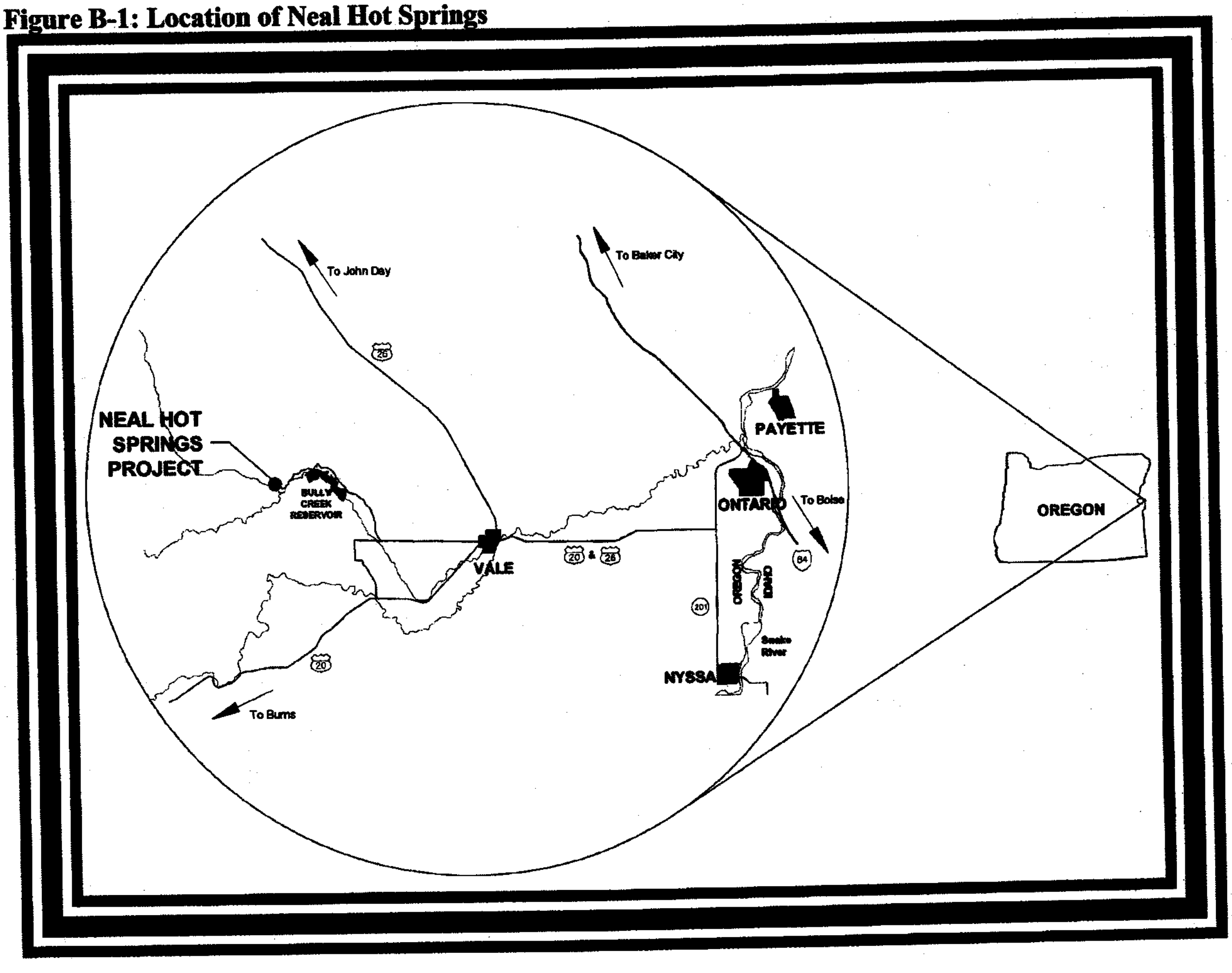
Expected Annual Average Capacity from the Facility:
The facility is expected to provide between 14,000 – 25,000 kW annual average capacity, excluding Forced and Scheduled Outages. This will be updated to a single annual average design capacity number as part of the requirements of the fourth Project Milestone of Appendix H and will be used in the Annual Output Forecast (Section 8.5.4).

B-2 LOCATION OF FACILITY

The Neal Hot Springs geothermal resource is located in north-central Malheur County, Oregon, 12 miles west-northwest of the town of Vale, Figure B-1. The project encompasses approximately 6,300 acres of private land leased from JR Land and Livestock Inc. and Cyprus Gold, all located in the Bully Creek Drainage. Equipment and wells will be located in Sections 5, 8, and 9, Township 18 South, Range 43 East, Willamette Meridian

Access is provided by state and county road systems to the project site. Travel west on State Highway 20 & 26 from Ontario Oregon to Vale Oregon. On the west edge of Vale turn right on Graham road, and then west 5.2 miles to the Bully Creek Road. Travel north and west on Bully Creek road approximately 8 miles to the project site.

Figure B-1: Location of Neal Hot Springs



APPENDIX C

TO

POWER PURCHASE AGREEMENT

BETWEEN

USG OREGON LLC

AND

IDAHO POWER COMPANY

SAMPLE FORM OF SELLER GUARANTY

($ XXX, 000)

_____________ __, 20__

Idaho Power Company
PO Box 70
Boise, Idaho 83707
Fax: ________________

Ladies and Gentlemen:

The ____________________(the "Guarantor"), a corporation duly organized under the laws of the State of _____________ is the ___________ of, a limited liability company duly organized under the laws of the State of _________ (the "Company"). Guarantor understands and acknowledges that Idaho Power Company, an Idaho corporation ("Buyer"), has entered into that certain Power Purchase Agreement between the Company and Buyer dated as of the effective date hereof (the "Power Purchase Agreement"). For value received, and under the provisions of the Power Purchase Agreement, Guarantor hereby unconditionally and, subject to the provisions of the fifth and sixth paragraphs hereof, irrevocably guarantees the prompt and complete payment as and when due, whether by acceleration or otherwise, of the payment obligations, whether now in existence or hereafter arising, under the Power Purchase Agreement (which guaranty, along with the other terms and conditions set forth herein, is hereafter referred to as the "Guaranty"). This Guaranty is one of payment and not of collection. Capitalized terms used but not defined in this Guaranty have the meaning given to them in the Power Purchase Agreement.

The maximum aggregate liability of the Guarantor in respect of amounts claimed by Buyer under or pursuant to this Guaranty shall at no time exceed an amount equal to _________________________ dollars ($________); provided, however, that Guarantor also guaranties payment in full (that is, without limitation as to amount) of any reasonable out-of-pocket legal fees, costs and/or expenses, whether at trial, on appeal or in any arbitration, by Buyer in connection with prevailing in enforcing the terms of this Guaranty.

The Guarantor hereby waives notice of acceptance of this Guaranty and notice of any obligation or liability to which it may apply, and waives presentment, demand for payment, protest, notice of dishonor or non-payment of any such obligation or liability, suit or the taking of other action by Buyer against, and any other notice to, the Company, the Guarantor or others.

Buyer may at any time and from time to time without notice to or consent of the Guarantor and without impairing or releasing the obligations of the Guarantor hereunder: (1) agree with the Company to make any change in the terms of any obligation or liability of the Company to Buyer, including any modification or amendment to the Power Purchase Sales Agreement, (2) take or fail to take any action of any kind in respect of any security for any obligation or liability of the Company to Buyer, (3) exercise or refrain from exercising any rights against the Company or others, (4) fail to first take action against the Company for amounts due under the Power Purchase Agreement, and/or (5) compromise or subordinate any obligation or liability of the Company to Buyer including any security therefore. Any other suretyship defenses are hereby waived by the Guarantor.

This Guaranty shall terminate on the earlier to occur of (i) the substitution of an alternate form of Seller Performance Assurance in accordance with the Power Purchase Agreement; and (ii) the later of (A) the termination or expiration of the Power Purchase Agreement and (B) the satisfaction of all obligations of the Company under the Power Purchase Agreement. Notwithstanding the foregoing, the Guarantor further agrees that if at any time payment, or any part thereof, of any of the obligations guaranteed hereunder, is rescinded, is demanded to be returned and/or must otherwise be restored or returned by Buyer in connection with the bankruptcy, insolvency, dissolution, reorganization or similar proceeding of the Company, this Guaranty shall continue to be effective or be reinstated as the case may be; provided that this Guaranty may not be reinstated for any reason after its termination under clause (i) of this paragraph.

Guarantor may not assign its rights nor delegate its obligations under this Guaranty, in whole or in part, without prior written consent of Buyer, and any purported assignment or delegation absent such consent is void, except for an assignment and delegation of all of the Guarantor's rights and obligations hereunder in whatever form the Guarantor determines may be appropriate to a partnership, corporation, trust or other organization in whatever form that succeeds to all or substantially all of the Guarantor's assets and business and that assumes such obligations by contract, operation of law or otherwise. Upon any such delegation and assumption of obligations, the Guarantor shall be relieved of and fully discharged from all obligations hereunder, whether such obligations arose before or after such delegation and assumption.

In the event any payment owing to Buyer under the Power Purchase Agreement or under this Guaranty is not promptly and completely paid as and when due, any indebtedness of Company to Guarantor and any payment or distribution right held by Guarantor against the Company shall be subordinated to the due and unpaid indebtedness to Buyer until paid in full. Guarantor shall have no right of subrogation until the Company's due and unpaid indebtedness to Buyer is paid in full.

This Guaranty constitutes the entire agreement and supersedes all prior agreements and understandings, both written and oral, between Guarantor and Buyer with respect to the subject matter hereof. This Guaranty may not be modified except pursuant to a written instrument signed by Buyer and Guarantor. The execution, delivery and performance of this Guaranty have been duly authorized by all requisite corporate action on the part of the Guarantor. The provisions of this Guaranty are severable, and if any clause or provision shall be held invalid or unenforceable in whole or in part, then such invalidity or unenforceability shall affect only such clause or provision, or part thereof, and shall not affect the validity or enforceability of any other clause or provision.

THIS GUARANTY SHALL BE GOVERNED BY AND CONSTRUED IN ACCORDANCE WITH THE INTERNAL LAWS OF THE STATE OF _______ WITHOUT GIVING EFFECT TO PRINCIPLES OF CONFLICTS OF LAW. GUARANTOR AGREES TO THE EXCLUSIVE JURISDICTION OF COURTS LOCATED IN THE STATE OF_____ , UNITED STATES OF AMERICA, OVER ANY DISPUTES ARISING UNDER OR RELATING TO THIS GUARANTY.

Very truly yours,

____

By: ______________________________________
Authorized Officer

APPENDIX D

TO

POWER PURCHASE AGREEMENT

BETWEEN

USG OREGON LLC

AND

IDAHO POWER COMPANY

NET ENERGY SHORTFALL PRICE AND ANNUAL CAP

Net Energy Shortfall Price The Net Energy Shortfall Price shall be (1) the mathematical average of the individual Contract Month's monthly Market Energy Cost values of the applicable Annual Guaranteed Output period or (2) one hundred fifty percent (150%) of the Contract Price specified in Appendix A for the month of June for the Calendar Year which corresponds to that of the first month of the Annual Guaranteed Output period, whichever is less, minus the Contract Price as specified in Appendix A for the month of June for the Calendar Year which corresponds to that of the first month of the Annual Guaranteed Output period. If this Net Energy Shortfall Price calculation results in a value less than zero (0) then the result will be zero (0).

Example 1

A Net Energy Shortfall occurs for the Contract Year of March 1, 2016 through February 28, 2017:

Contract Price: 109.27 mills/kWh

Mathematical average of the Contract Month's monthly Market Energy Cost values for the period of March 1, 2016 through February 28, 2017:

40.00 mills/kWh

150% of the Contract Price: 109.27 * 150% = 163.91 mills/kWh

Net Energy Shortfall Price calculation

The average Market Energy Cost (40.00) is less than 150% of the Annual Rate (163.91). Therefore the Net Energy Shortfall Price calculation is equal to:

Market Energy Cost (40.00) minus Contract Price (109.27) = -69.27

As the calculation results in a value less than 0, (-69.27) the Net Energy Shortfall Price equals 0.00 mills/kWh.

Example 2

A Net Energy Shortfall occurs for the Contract Year of March 1, 2016 through February 28, 2017:

Contract Price: 109.27 mills/kWh

Mathematical average of the Contract Month's monthly Market Energy Cost values for the period of March 1, 2016 through February 28, 2017:

125.00 mills/kWh

150% of the Contract Price: 109.27 * 150% = 163.91 mills/kWh

Net Energy Shortfall Price calculation

The average Market Energy Cost (125.00) is less than 150% of the Annual Rate (163.91). Therefore the Net Energy Shortfall Price calculation is equal to:

Market Energy Cost (125.00) minus Contract Price (109.27) = 15.73

Net Energy Shortfall Price equals 15.73 mills/kWh

Example 3

A Net Energy Shortfall occurs for the Contract Year of March 1, 2016 through February 28, 2017:

Contract Price: 109.27 mills/kWh

Mathematical average of the Contract Month's monthly Market Energy Cost values for the period of March 1, 2016 through February 28, 2017:

180.00 mills/kWh

150% of the Contract Price: 109.27 * 150% = 163.91 mills/kWh

Net Energy Shortfall Price calculation

The average Market Energy Cost (180.00) is greater than 150% of the AnnualRate (163.91). Therefore the Net Energy Shortfall Price calculation is equal to:

150% of Contract Price (163.91) minus Contract Price (109.27) = 54.64

Net Energy Shortfall Price equals 54.64 mills/kWh

Net Energy Shortfall Damages Cap

Contract Year	Net Energy Shortfall Damages Cap		Contract Year	Net Energy Shortfall Damages Cap
1	$0.00		14	$573,073
2	$0.00		15	$590,265
3	$414,000		16	$607,973
4	$426,420		17	$626,212
5	$439,213		18	$644,998
6	$452,389		19	$664,349
7	$465,961		20	$684,279
8	$479,939		21	$690,000
9	$494,338		22	$690,000
10	$509,168		23	$690,000
11	$524,443		24	$690,000
12	$540,176		25	See Note 1
13	$556,382			

Note 1 – The Net Energy Shortfall Damages Cap in the final year shall be $690,000 prorated to the number of months in the Annual Output Forecast.

APPENDIX E

TO

POWER PURCHASE AGREEMENT

BETWEEN

USG OREGON LLC

AND

IDAHO POWER COMPANY

ENGINEERING CERTIFICATIONS

Continued on next page

ENGINEER'S CERTIFICATION

OF

OPERATIONS & MAINTENANCE POLICY

The undersigned ____________________________________, on behalf of himself and ____________________________________, hereinafter collectively referred to as "Engineer," hereby states and certifies to the Seller as follows:

1. That Engineer is a Licensed Professional Engineer in good standing.

2. That Engineer has reviewed the Power Purchase Agreement, hereinafter "Agreement," between Idaho Power as Buyer, and ____________________ as Seller, dated ________________________.

3. That the geothermal power production Facility which is the subject of the Agreement and this statement is identified as the ______________________________ and is hereinafter referred to as the "Facility."

4. That the Facility is located in Section ____ Township _______, Range ________, _________________, _____________ County, Oregon.

5. That Engineer recognizes that the Agreement provides for the Facility to furnish electrical energy to Idaho Power for a twenty five (25) year period.

6. That Engineer has substantial experience in the design, construction and operation of electric power plants of the same type as this Facility.

7. The Engineer will identify any material economic relationship to the Design Engineer of this Facility.

8. That Engineer has reviewed and/or supervised the review of the operation and maintenance policies ("O&M") for this Facility and it is his professional opinion that, provided said Facility has been designed and built to appropriate standards, adherence to said O&M policies will result in the Facility's producing at or near the design electrical output, efficiency and plant factor for a twenty five (25) year period.

9. That Engineer recognizes that Idaho Power, in accordance with Article 3 and 4 of the Agreement, is relying on Engineer's representations and opinions contained in this Statement.

10. That Engineer certifies that the above statements are complete, true and accurate to the best of his knowledge and therefore sets his hand and seal below.

By ______________________________

(P.E. Stamp)

Date ______________________________

ENGINEER'S CERTIFICATION

OF

ONGOING OPERATIONS AND MAINTENANCE

The undersigned ______________________________, on behalf of himself and ______________________________ hereinafter collectively referred to as "Engineer," hereby states and certifies to the Seller as follows:

1. That Engineer is a Licensed Professional Engineer in good standing.

2. That Engineer has reviewed the Power Purchase Agreement, hereinafter "Agreement," between Idaho Power as Buyer, and ______________________ as Seller, dated ______________________.

3. That the geothermal power production Facility which is the subject of the Agreement and this statement is identified as the ______________________________ and is hereinafter referred to as the "Facility."

4. That the Facility is located in Section ____ Township ______, Range ________, ________________, ____________ County, Oregon.

5. That Engineer recognizes that the Agreement provides for the Facility to furnish electrical energy to Idaho Power for a twenty five (25) year period.

6. That Engineer has substantial experience in the design, construction and operation of electric power plants of the same type as this Facility.

7. The Engineer shall identify any material economic relationship to the Design Engineer of this Facility.

8. That Engineer has made a physical inspection of said Facility, its operations and maintenance records since the last previous certified inspection. It is Engineer's professional opinion, based on the Facility's appearance, that its ongoing O&M has been substantially in

accordance with said O&M Policy; that it is in reasonably good operating condition; and that if adherence to said O&M Policy continues, the Facility will continue producing at or near its design electrical output, efficiency and plant factor, within the limits of the geothermal reservoir capability of the Facility for the remaining ______ years of the Agreement.

9. That Engineer recognizes that Idaho Power, in accordance with Article 3 and 4 of the Agreement, is relying on Engineer's representations and opinions contained in this Statement.

10. That Engineer certifies that the above statements are complete, true and accurate to the best of his knowledge and therefore sets his hand and seal below.

By ______________________________

(P.E. Stamp)

Date ________________________________

ENGINEER'S CERTIFICATION

OF

DESIGN & CONSTRUCTION ADEQUACY

The undersigned ___________________________________, on behalf of himself and _____________________________________, hereinafter collectively referred to as "Engineer", hereby states and certifies to Idaho Power as follows:

1. That Engineer is a Licensed Professional Engineer in good standing.

2. That Engineer has reviewed the Power Purchase Agreement, hereinafter "Agreement," between Idaho Power as Buyer, and ____________________ as Seller, dated ________________________.

3. That the geothermal power production Facility which is the subject of the Agreement and this statement is identified as the _________________________________ and is hereinafter referred to as the "Facility."

4. That the Facility is located in Section ____ Township _______, Range ________, ____________________, ____________ County, Oregon.

5. That Engineer recognizes that the Agreement provides for the Facility to furnish electrical energy to Idaho Power for a twenty five (25) year period.

6. That Engineer has substantial experience in the design, construction and operation of electric power plants of the same type as this Facility.

7. The Engineer shall identify any material economic relationship to the Design Engineer of this Facility and has made the analysis of the plans and specifications independently.

8. That Engineer has reviewed the engineering design and construction of the Facility, including the civil work, electrical work, generating equipment, prime mover

conveyance system, Seller furnished Interconnection Facilities and other Facility facilities and equipment.

9. That the Facility has been constructed in accordance with said plans and specifications, all applicable codes and consistent with Good Utility Practices as that term is described in the Agreement.

10. That the design and construction of the Facility is such that with reasonable and prudent operation and maintenance practices by Seller, the Facility is capable of performing in accordance with the terms of the Agreement and with Prudent Electrical Practices for a _________ (______) year period.

11. That Engineer recognizes that Idaho Power, in accordance with Article 3 and 4 of the Agreement, in interconnecting the Facility with its system, is relying on Engineer's representations and opinions contained in this Statement.

12. That Engineer certifies that the above statements are complete, true and accurate to the best of his knowledge and therefore sets his hand and seal below.

By ______________________________

(P.E. Stamp)

Date ____________________________

APPENDIX F

TO

POWER PURCHASE AGREEMENT

BETWEEN

USG OREGON LLC

AND

IDAHO POWER COMPANY

COMMUNICATIONS

Buyer Contact Information

Idaho Power Company
1221 West Idaho Street
Boise, ID 83702
Telephone: (208) 388-2200

Mr. Karl Bokenkamp
General Manager Power Supply Operations & Planning
Telephone: (208) 388-2482
Email: kbokenkamp@idahopower.com

Mr. Mel Chick
Supervisor Generation Dispatch
Telephone: (208) 388-6476
Email: mchick@idahopower.com

Ms. Tess Park
Manager Power Operations
Telephone: (208) 388-5626
Email: tpark2@idahopower.com

Mr. Chris Nebrigich
Leader, Transaction Specialist
Telephone: (208) 388-2988
Email: tnebrigich@idahopower.com

Seller Contact Information

USG Oregon LLC
1505 Tyrell Lane
Boise, ID 83706
208-424-1027

Daniel Kunz
Chief Executive Office
dkunz@usgeothermal.com

Kerry Hawkley
Chief Financial Officer
khawkley@usgeothermal.com

24-Hour Project Operational Contact (To be provided prior to First Energy Date)

Name: ____________________
Telephone Number: ________________
Cell Phone: __________________________________
E-Mail: ______________________________________
Fax: _____________________

Project On-site Contact Information (To be provided prior to First Energy Date)

____
____
____
____
Phone: _______________
E-mail: _____________________

APPENDIX G

TO

POWER PURCHASE AGREEMENT

BETWEEN

USG OREGON LLC

AND

IDAHO POWER COMPANY

ONE-LINE DIAGRAM OF GENERATING FACILITY

AND

INTERCONNECTION FACILITIES

This Appendix shall contain a one-line diagram of the proposed Facility, Interconnection Facilities, Point of Delivery, ownership and location of Meters at the Metering Point and any other data that is deemed to be pertinent in identifying ownership of equipment, energy deliveries to the Buyer and/or any other responsibilities of the Parties pertinent to this Agreement.

No later than thirty (30) days after the execution of the Interconnection Agreement, the Seller shall provide updates to this one-line diagram and/or confirmation that the previously provided one-line diagram is still accurate.

APPENDIX H

TO

POWER PURCHASE AGREEMENT

BETWEEN

USG OREGON LLC

AND

IDAHO POWER COMPANY

PROJECT MILESTONE REQUIREMENTS AND COMPLETION DATES

All Project Milestones may be completed earlier then the stated time at the sole option of the Seller. Failure to complete the requirements of a Project Milestone by the specified completion date shall be an event of default.

Project Milestones –

1. **Exploration Schedule**

   Delivery of a report and exploration schedule to the Buyer.

   Completion Date: The required documentation is due within thirty (30) days of the date that final Commission Approval is received for this Agreement.

   Documentation: Seller shall provide the Buyer a schedule of the additional exploration activities at this site beyond what has been completed as of the date of this Agreement. This schedule shall include but not be limited to key activities required to establish an estimated MW rating of a potential generation facility at this site, and the reporting requirements of Section 5.2.

2. **Additional Well Development**

   Seller shall have commenced the drilling of an additional geothermal fluid production or injection well in addition to the single existing well.

   Completion Date: June 30, 2011.

Documentation:	Seller shall provide the Buyer with written documentation of the commencement of well drilling.

3. **<u>Exploration Completion and Resource Feasibility Report</u>**

Seller shall have completed adequate exploration and study of the proposed Site to enable the Seller to establish the estimated electrical generation capability of the geothermal resource.

Completion Date:	The required documentation shall be delivered to Buyer no later than December 31, 2013
Documentation:	The Seller shall supply the Buyer a summary report including the Seller's statement of the kW rating of the Facility this geothermal resource is able to support for the term of this Agreement. The report shall include a summary of the findings of the various studies and exploration and a recommendation from the Seller as to the site's ability to accommodate the Facility as envisioned by this Agreement. This recommendation shall reference and be supported by the detailed studies and exploration. Information contained in the report shall include, but not be limited to, information on the projected electrical generation capability of this site, ability of the site to sustain the projected electrical generation facility, and recommended site development plans to maximize the usage of the identified geothermal resource. Buyer shall have the right to request additional detail supporting the summary report and/or discussions with the parties that performed or validated the studies.

4. **<u>Executed EPC Agreement and NTP</u>**

Seller shall have executed an engineering, procurement and construction (EPC) contract with the primary power plant contractor for construction of the Facility and a notice–to-proceed (NTP) shall have been issued.

Completion Date:	Seller shall have issued the required NTP described above no later than December 31, 2014

Documentation:	Seller shall provide the Buyer with written confirmation that a signed NTP was issued and the date on which that NTP was issued. Seller shall also meet the documentation requirements of the Agreement that reference the fourth Project Milestone included in Article 3.

CASE NO. GNR-E-11-03

PETITION FOR RECONSIDERATION
OF J.R. SIMPLOT COMPANY AND CLEARWATER PAPER
CORPORATION

ATTACHMENT 2

Office of the Secretary
Service Date
May 1, 2006

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR APPROVAL OF A FIRM ENERGY SALES AGREEMENT FOR THE SALE AND PURCHASE OF ELECTRIC ENERGY BETWEEN IDAHO POWER COMPANY AND J. R. SIMPLOT COMPANY	)	**CASE NO. IPC-E-06-3** **ORDER NO. 30028**

On February 10, 2006, Idaho Power Company (Idaho Power; Company) filed an Application with the Idaho Public Utilities Commission (Commission) requesting approval of a Firm Energy Sales Agreement between Idaho Power and J.R. Simplot Company (Simplot) dated February 8, 2006 (Agreement).

Simplot currently owns, operates and maintains an 18.75 MW cogeneration facility (Project) at its industrial site near Pocatello, Idaho. The facility is located in the South 1/2 of Section 7, Township 6 South, Range 34 East, Boise Meridian, Power County, Idaho. The Project is a qualified cogeneration facility under the applicable provisions of the Public Utility Regulatory Policies Act of 1978 (PURPA). As reflected in the Company's Application, the Simplot Project is currently interconnected to Idaho Power and is selling energy to Idaho Power as a qualifying facility (QF) in accordance with a Firm Energy Sales Agreement dated June 18, 2004 and an approved effective date of March 1, 2004. Reference Case No. IPC-E-04-16, Order No. 29577.

The existing Firm Energy Sales Agreement is a one-year agreement which permits automatic renewals of one year on March 1 of each year. The Agreement also specifies that, with appropriate notice, either party may terminate the Agreement effective March 1. Simplot has timely requested to terminate the existing Firm Energy Sales Agreement for this Project and enter into a new Firm Energy Sales Agreement for its Pocatello facility. Idaho Power contends that the terms of the new Agreement conform to the terms and conditions of Commission Order No. 29632 (*U.S. Geothermal et al. v. Idaho Power*) and Commission avoided cost Order No. 29646 (Case No. IPC-E-04-25) for energy deliveries of less than 10 aMW.

Under the terms of the submitted Agreement, Simplot has elected to contract with Idaho Power for a seven-year term. The Agreement contains non-levelized published avoided cost rates established by the Commission in Order No. 29646 (December 1, 2004) for energy deliveries less than 10 aMW for a contract year beginning February 8, 2006.

As reflected in Agreement ¶ 1.13 and specified in Item B-3 of the Agreement Appendix B, the maximum capacity of the cogeneration facility is 12 MW. As defined in Agreement ¶ 1.9 and as described further in ¶ 4.1.3, Simplot will be required to provide data on the facility that Idaho Power will use to determine whether, under normal and/or average conditions, the facility will not exceed 10 aMW on a monthly basis. Idaho Power states that it has reviewed the historical generation data for the Simplot facility. As reflected in Agreement ¶ 7.3, should the Simplot facility exceed 10 aMW on a monthly basis, Idaho Power will accept any energy (Inadvertent Energy) that does not exceed the maximum capacity amounts; however, Idaho Power will not purchase or pay for this Inadvertent Energy.

Agreement ¶ 25 provides that the Agreement will not become effective until the Commission has approved without change all the Agreement terms and conditions and declared that all payments to Simplot that Idaho Power makes for purchases of energy will be allowed as prudently incurred expenses for ratemaking purposes.

On March 3, 2006, the Commission issued Notices of Application and Modified Procedure in Case No. IPC-E-06-3. The deadline for filing written comments was March 24, 2006. Comments were received from Commission Staff and a Caldwell customer of the Company. The customer sees no reason that Idaho Power can't buy Simplot's power as long as the utility doesn't come back next week and request a rate increase. Commission Staff recommends that the Agreement be approved.

Staff notes that there are two primary differences between the submitted Agreement and the one it replaces. First, under the terms of the submitted Agreement, Simplot has elected to contract with Idaho Power for a seven-year term. This eliminates the automatic annual renewals that occurred under the prior Agreement. Staff notes that because the prior Agreement was renewed automatically at the prevailing avoided cost rates during each renewal year, the submitted Agreement contains the same rates as it would have contained under the prior Agreement. The second primary difference revises the definition of the 10 MW threshold for eligibility for published avoided cost rates. Under the prior Agreement, Simplot was limited to generating no more than 10,000 kWh per hour. Under the submitted Agreement, Simplot is limited to generating no more than 10 aMW per month. This revised generation limit is consistent with the definition of the 10 MW threshold established in the *U.S Geothermal* case (Order No. 29632).

Commission Findings

The Commission has reviewed and considered the filings of record in Case No. IPC-E-06-3, including the underlying Agreement and the comments and recommendations of Commission Staff. We have also reviewed public comment filed in support of the project.

Idaho Power requests approval of a February 8, 2006 Firm Energy Sales Agreement between Idaho Power and J.R. Simplot Company for Commission consideration and approval. The nameplate rating of the cogeneration facility is 18.75 MW. The contract is for a seven-year term and contains non-levelized published avoided cost rates for energy deliveries not exceeding 10 aMW on a monthly basis. The Commission finds that the Agreement submitted in this case contains acceptable contract provisions and rates and comports with the terms and conditions of Order Nos. 29632 and 29682 in Case Nos. IPC-E-04-8; 04-10.

The Commission finds it reasonable that the submitted Agreement be approved without further notice or procedure. IDAPA 31.01.01.204. We further find it reasonable to allow payments made under the Agreement as prudently occurred expenses for ratemaking purposes.

CONCLUSIONS OF LAW

The Idaho Public Utilities Commission has jurisdiction over Idaho Power Company, an electric utility, pursuant to the authority and power granted it under Title 61 of the Idaho Code and the Public Utility Regulatory Policies Act of 1978 (PURPA).

The Commission has authority under PURPA and the implementing regulations of the Federal Energy Regulatory Commission (FERC) to set avoided costs, to order electric utilities to enter into fixed term obligations for the purchase of energy from qualified facilities and to implement FERC rules.

O R D E R

In consideration of the foregoing, IT IS HEREBY ORDERED and the Commission does hereby approve the February 8, 2006 Firm Energy Sales Agreement between Idaho Power Company and J.R. Simplot Company for an effective date of February 8, 2006.

THIS IS A FINAL ORDER. Any person interested in this Order may petition for reconsideration within twenty-one (21) days of the service date of this Order. Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. See *Idaho Code* § 61-626.

DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 1st day of ~~April~~ May 2006.

PAUL KJELLANDER, PRESIDENT

MARSHA H. SMITH, COMMISSIONER

DENNIS S. HANSEN, COMMISSIONER

ATTEST:

Jean D. Jewell
Commission Secretary

bls/O:IPC-E-06-03_sw

IDAHO POWER
An IDACORP Company

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

RECEIVED
2006 FEB 10 AM 7:59
IDAHO PUBLIC
UTILITIES COMMISSION

MONICA MOEN
Attorney

February 9, 2006

Jean D. Jewell, Secretary
Idaho Public Utilities Commission
472 West Washington Street
P. O. Box 83720
Boise, Idaho 83720-0074

Re: Case No. IPC-E-06-03
Application For Approval of A Firm Energy Sales Agreement Between Idaho Power Company and J.R. Simplot Company

Dear Ms. Jewell:

Please find enclosed for filing an original and seven (7) copies of Idaho Power Company's Application for the approval of a Firm Energy Sales Agreement between Idaho Power Company and J.R. Simplot Company.

I would appreciate it if you would return a stamped copy of this transmittal letter in the enclosed self-addressed, stamped envelope.

Very truly yours,

Monica Moen

Monica Moen

MM:jb
Enclosures

Telephone (208) 388-2692, Fax (208) 388-6936, E-mail MMoen@idahopower.com

MONICA MOEN, ISB # 5734
BARTON KLINE, ISB # 1526
Idaho Power Company
1221 West Idaho Street
P. O. Box 70
Boise, Idaho 83707
Telephone: (208) 388-2692
FAX Telephone: (208) 388-6936

Attorney for Idaho Power Company

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR APPROVAL OF AN AGREEMENT FOR SALE AND PURCHASE OF ELECTRIC ENERGY BETWEEN IDAHO POWER COMPANY AND THE J. R. SIMPLOT COMPANY	CASE NO. IPC-E-06-03 APPLICATION

COMES NOW Idaho Power Company ("Idaho Power" or the "Company") and, pursuant to IPUC Rule of Procedure 52, hereby applies for an Idaho Public Utilities Commission ("IPUC" or the "Commission") Order approving an Agreement between Idaho Power and the J. R. Simplot Company ("Simplot") under which Simplot would sell and Idaho Power would purchase electric energy generated by the Simplot cogeneration facility located at the J R Simplot industrial site near Pocatello, Idaho.

This Application is based on the following:

I.

Simplot currently owns, operates and maintains a cogeneration facility ("Project") at its industrial site near Pocatello, Idaho. The Project is a qualified small power production facility under the applicable provisions of the Public Utilities Regulatory Policy Act of 1978 ("PURPA").

II.

This Project is currently interconnected to Idaho Power and is selling energy to Idaho Power as a Qualifying Facility in accordance with a Firm Energy Sales agreement dated March 1, 2004. The Project has been selling energy to Idaho Power since January 1991. Prior to the March 1, 2004 agreement, the Project was selling energy to the Company under a Firm Energy Sales agreement dated January 24, 1991 and subsequently amended on November 30, 1993 and February 23, 2001. Simplot has requested a new Firm Energy Sales Agreement for this Project to take effect on March 1, 2006 upon expiration of the March 1, 2004 agreement.

III.

The March 1, 2004 agreement is a one-year agreement which permits automatic renewals of one year on March 1 of each year. The agreement also specifies that, with appropriate notice, either party may terminate the agreement effective March 1. Simplot has timely requested to terminate the March 1, 2004 Firm Energy Sales Agreement for this Project and enter into a new Firm Energy Sales Agreement for this Facility. On February 8, 2006, Idaho Power and Simplot entered into a Firm Energy Sales Agreement ("Agreement") pursuant to the terms and conditions of Commission Order No. 29632 and Commission Order 29646 for energy deliveries of less than 10 average MW. Under the terms of that Agreement, Simplot elected to contract with Idaho Power for a 7-year term. Simplot further elected to contract with the Company using the Non-Levelized Published Avoided Cost Rate as currently established by the Commission for energy deliveries of less than 10 average

MW. A copy of the Agreement between Idaho Power and Simplot is attached hereto as Exhibit 1.

IV.

This Agreement is similar to recent agreements entered into by Idaho Power and approved by the Commission (e.g., Pilgrim Stage Station Wind Park (IPUC Order 29771) Oregon Trails Wind Park (IPUC Order 29772), Tuana Gulch Wind Park (IPUC Order 29773) and the Thousand Springs Wind Park (IPUC Order 29770)). The Simplot Agreement contains the various PURPA terms and conditions previously approved by the Commission in other PURPA agreements and as revised by Commission Order No. 29632 in Case No. IPC-E-04-8 (US Geothermal complaint).

V.

The Maximum Capacity of this Facility is 12 MW as defined in Paragraph 1.13 and specified in Item B-3 of Appendix B of the Agreement. As defined in Paragraph 1.9 of the Agreement and as described in Paragraph 4.1.3 of the Agreement, Simplot will be required to provide data on the Facility that Idaho Power will use to determine whether, under normal and/or average conditions, the Facility will not exceed 10 average MW on a monthly basis. Idaho Power has reviewed the historical generation data for this Facility. The data supports Simplot's representation that, under current normal and/or average conditions, the Facility in the recent past has not exceeded 10 average MW in generation on a monthly basis. Furthermore, as described in Paragraph 7.3 of the Agreement, should the Facility exceed 10 average MW on a monthly basis, Idaho Power will accept any energy ("Inadvertent Energy") that does not exceed the Maximum Capacity Amount; however, Idaho Power will not purchase or pay for this Inadvertent Energy.

VI.

Section 25 of the Agreement provides that the Agreement will not become effective until the Commission has approved all of the Agreement's terms and conditions and declared that all payments Idaho Power makes for purchases of energy to Simplot will be allowed as prudently incurred expenses for ratemaking purposes.

VII.

Within this Agreement, various requirements have been placed upon Simplot in order for Idaho Power to continue to accept energy deliveries from this Project. Idaho Power will monitor compliance with these initial requirements in addition to the ongoing requirements through the full term of this Agreement. Should the Commission approve this Agreement, Idaho Power intends to consider the Effective Date of the Agreement to be February 8, 2006.

VIII.

The Agreement, as signed and submitted by the Parties thereto, contains Non-Levelized Published Avoided Cost Rates in conformity with applicable IPUC Orders. All applicable interconnection charges and monthly Operation and Maintenance charges under Schedule 72 will be assessed Simplot.

IX.

Service of pleadings, exhibits, orders and other documents relating to this proceeding should be served on the following:

Monica B. Moen, Attorney II
Barton L. Kline, Senior Attorney
Idaho Power Company
P.O. Box 70
Boise, Idaho 83707
mmoen@idahopower.com
bkline@idahopower.com

Randy C. Allphin
Contract Administrator
Idaho Power Company
P.O. Box 70
Boise, Idaho 83707
rallphin@idahopower.com

NOW, THEREFORE, based on the foregoing, Idaho Power Company hereby requests that the Commission issue its Order:

(1) Approving the Firm Energy Sales Agreement between Idaho Power Company and J R Simplot Company without change or condition; and

(2) Declaring that all payments for purchases of energy under the firm Energy Sales Agreement between Idaho Power Company and J R Simplot Company be allowed as prudently incurred expenses for ratemaking purposes.

Respectfully submitted this 9th day of February 2006.

Monica B. Moen

MONICA B. MOEN
Attorney for Idaho Power Company

CERTIFICATE OF MAILING

I HEREBY CERTIFY that on the 9th day of February 2006, I served a true and correct copy of the within and foregoing APPLICATION upon the following named parties by the method indicated below, and addressed to the following:

J R Simplot Company	___	Hand Delivered
Attn: David Hawk	x	U.S. Mail
P.O. Box 27	___	Overnight Mail
Boise, ID 83707	___	FAX

Monica B. Moe

MONICA B. MOEN

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-06-03

IDAHO POWER COMPANY

EXHIBIT 1

FIRM ENERGY SALES AGREEMENT

BETWEEN

IDAHO POWER COMPANY

AND

J.R. SIMPLOT COMPANY

TABLE OF CONTENTS

FIRM ENERGY SALES AGREEMENT
(10 aMW or Less)

SIMPLOT - POCATELLO

Project Number: 41866112

THIS AGREEMENT, entered into on this 8 day of February 2006 between J R SIMPLOT COMPANY, a Nevada Corporation (Seller), and IDAHO POWER COMPANY, an Idaho corporation (Idaho Power), hereinafter sometimes referred to collectively as "Parties" or individually as "Party."

WITNESSETH:

WHEREAS, Seller has designed, constructed, owns, maintains and operates an electric generation facility; and

WHEREAS, Seller wishes to sell, and Idaho Power is willing to purchase, firm electric energy produced by the Seller's Facility.

THEREFORE, In consideration of the mutual covenants and agreements hereinafter set forth, the Parties agree as follows:

ARTICLE I: DEFINITIONS

As used in this Agreement and the appendices attached hereto, the following terms shall have the following meanings:

1.1 "Commission" - The Idaho Public Utilities Commission.

1.2 "Contract Year" - The period commencing each calendar year on the same calendar date as the Operation Date and ending 364 days thereafter.

1.3 "Designated Dispatch Facility" - Idaho Power's Systems Operations Group, or any subsequent group designated by Idaho Power.

1.4 "Disconnection Equipment" - All equipment specified in Schedule 72 and the Generation Interconnection Process and any additional equipment specified in Appendix B or Appendix D.

1.5 "Facility" - That electric generation facility described in Appendix B of this Agreement.

1.6 "Generation Interconnection Process" – Idaho Power's generation interconnection application and engineering review process developed to ensure a safe and reliable generation interconnection in compliance with all applicable regulatory requirements, Prudent Electrical Practices and national safety standards.

1.7 "Inadvertent Energy" – Electric energy Seller does not intend to generate. Inadvertent energy is more particularly described in paragraph 7.3 of this Agreement.

1.8 "Interconnection Facilities" - All equipment specified in Schedule 72 and the Generation Interconnection Process and any additional equipment specified in Appendix B or Appendix D.

1.9 "Initial Capacity Determination" – The process by which Idaho Power confirms that under normal or average design conditions the Facility will generate at no more than 10 average MW per month and is therefore eligible to be paid the published rates in accordance with Commission Order No. 29632.

1.10 "Losses" – The loss of electrical energy expressed in kilowatt hours (kWh) occurring as a result of the transformation and transmission of energy between the point where the Facility's energy is metered and the point the Facility's energy is delivered to the Idaho Power electrical system. The loss calculation formula will be as specified in Appendix B of this Agreement.

1.11 "Market Energy Cost" – Eighty-five percent (85%) of the weighted average of the daily on-peak and off-peak Dow Jones Mid-Columbia Index (Dow Jones Mid-C Index) prices for non-firm energy. If the Dow Jones Mid-Columbia Index price is discontinued by the reporting agency, both Parties will mutually agree upon a replacement index, which is similar to the Dow Jones Mid-Columbia Index. The selected replacement index will be consistent with other similar agreements and a commonly used index by the electrical industry.

1.12 "Material Breach" – A Default (paragraph 23.2.1) subject to paragraph 23.2.2.

1.13 "Maximum Capacity Amount" – The maximum capacity (MW) of the Facility will be as specified in Appendix B of this Agreement.

1.14 "Metering Equipment" - All equipment specified in Schedule 72, the Generation Interconnection Process, this Agreement and any additional equipment specified in Appendix B or Appendix D required to measure, record and telemeter power flows between the Seller's electric generation plant and Idaho Power's system.

1.15 "Net Energy" – All of the electric energy produced by the Facility, less Station Use, less Losses, expressed in kilowatt hours (kWh). Seller commits to deliver all Net Energy to Idaho Power at the Point of Delivery for the full term of the Agreement. Net Energy does not include Inadvertent Energy.

1.16 "Operation Date" – The beginning of the day specified in paragraph 5.2 of this Agreement.

1.17 "Point of Delivery" – The location specified in Appendix B, where Idaho Power's and the Seller's electrical facilities are interconnected.

1.18 "Prudent Electrical Practices" – Those practices, methods and equipment that are commonly and ordinarily used in electrical engineering and operations to operate electric equipment lawfully, safely, dependably, efficiently and economically.

1.19 "Schedule 72" – Idaho Power's Tariff No 101, Schedule 72 or its successor schedules as approved by the Commission.

1.20 "Season" – The three periods identified in paragraph 6.2.1 of this Agreement.

1.21 "Special Facilities" - Additions or alterations of transmission and/or distribution lines and transformers as described in Appendix B, Appendix D, Schedule 72 or the Generation Interconnection Process required to safely interconnect the Seller's Facility to the Idaho Power system.

1.22 "Station Use" – Electric energy that is used to operate equipment that is auxiliary or otherwise related to the production of electricity by the Facility.

1.23 "Surplus Energy" – (1) Net Energy produced by the Seller's Facility and delivered to the Idaho Power electrical system during the month which exceeds 110% of the monthly Net Energy Amount for the corresponding month specified in paragraph 6.2. or (2) If the Net Energy produced by the Seller's Facility and delivered to the Idaho Power electrical system during the month is less than 90% of the monthly Net Energy Amount for the corresponding month specified in paragraph 6.2, then all Net Energy delivered by the Facility to the Idaho Power electrical system for that given month or (3) All Net Energy produced by the Seller's Facility and delivered by the Facility to the Idaho Power electrical system prior to the satisfactory completion of all requirements of Article IV, Conditions to Continued Acceptance of Energy.

1.24 "Total Cost of the Facility" - The total cost of structures, equipment and appurtenances.

ARTICLE II: NO RELIANCE ON IDAHO POWER

2.1 Seller Independent Investigation - Seller warrants and represents to Idaho Power that in entering into this Agreement and the undertaking by Seller of the obligations set forth herein, Seller has investigated and determined that it is capable of performing hereunder and has not relied upon the advice, experience or expertise of Idaho Power in connection with the transactions contemplated by this Agreement.

2.2 Seller Independent Experts - All professionals or experts including, but not limited to, engineers, attorneys or accountants, that Seller may have consulted or relied on in undertaking the transactions contemplated by this Agreement have been solely those of Seller.

ARTICLE III: WARRANTIES

3.1 No Warranty by Idaho Power - Any review, acceptance or failure to review Seller's design, specifications, equipment or facilities shall not be an endorsement or a confirmation by Idaho Power and Idaho Power makes no warranties, expressed or implied, regarding any aspect of Seller's design, specifications, equipment or facilities, including, but not limited to, safety, durability, reliability, strength, capacity, adequacy or economic feasibility.

3.2 Qualifying Facility Status - Seller warrants that the Facility is a "Qualifying Facility," as that term is used and defined in 18 CFR §292.207. After initial qualification, Seller will take such steps as may be required to maintain the Facility's Qualifying Facility status during the term of this Agreement and Seller's failure to maintain Qualifying Facility status will be a Material Breach of this Agreement. Idaho Power reserves the right to review the Seller's Qualifying Facility status and associated support and compliance documents at anytime during the term of this Agreement.

ARTICLE IV: CONDITIONS TO CONTINUED ACCEPTANCE OF ENERGY

4.1 Prior to the Seller requesting an Operation Date and an Operation Date being assigned for this Agreement as specified in paragraph 5.2 of this Agreement, the following requirements shall be completed;

4.1.1 This Facility is currently interconnected to Idaho Power and is selling energy to Idaho Power as a Qualifying Facility in accordance with a Firm Energy Sales agreement dated March 1, 2004. The Seller shall submit proof to Idaho Power that all licenses, permits or approvals necessary for Seller to continue operations have been obtained from applicable federal, state or local authorities, including, but not limited to, evidence of compliance with Subpart B, 18 CFR 292.207.

4.1.1.1 As a condition of the Firm Energy Sales Agreement dated March 1, 2004, the Seller provided Idaho Power a letter (dated February 1, 2005) certifying that all licenses, permits or approvals necessary for Seller to continue operations were in full force and effect. Idaho Power will rely on this previous letter as still being accurate.

4.1.2 Opinion of Counsel – Seller shall submit to Idaho Power an Opinion Letter signed by an attorney admitted to practice and in good standing in the State of Idaho providing an opinion that Seller's licenses, permits and approvals as set forth in paragraph 4.1.1 above are legally and validly issued, are held in the name of the Seller and, based on a reasonable independent review, counsel is of the opinion that Seller is in substantial compliance with said permits as of the date of the Opinion Letter. The Opinion Letter will be in a form acceptable to Idaho Power and will acknowledge that the attorney rendering the opinion understands that Idaho Power is relying on said opinion. Idaho Power's acceptance of the form will not be unreasonably withheld. The Opinion Letter will be governed by and shall be interpreted in accordance with the legal opinion accord of the American Bar Association Section of Business Law (1991).

4.1.2.1 As a condition of the Firm Energy Sales Agreement dated March 1, 2004, the Seller provided Idaho Power an acceptable Opinion of Counsel letter (dated February 1, 2005). Idaho Power will rely on this previous letter as still being accurate.

4.1.3 Initial Capacity Determination - Submit to Idaho Power such data as Idaho Power may reasonably require to perform the Initial Capacity Determination. Such data will include but not be limited to, equipment specifications, prime mover data, resource characteristics, normal and/or average operating design conditions and Station Use data. Upon receipt of this information, Idaho Power will review the provided data and if necessary, request additional data to complete the Initial Capacity Determination within a reasonable time.

4.1.4 Engineer's Certifications - This Facility is currently interconnected to the Idaho Power system. The Seller will submit an Engineer's Certification of Operations and Maintenance ("O&M") Policy as described in Commission Order No. 21690. This certificate will be in the form specified in Appendix C but may be modified to the extent necessary to recognize the different engineering disciplines providing the certificates.

4.1.4.1 As a condition of the Firm Energy Sales Agreement dated March 1, 2004, the Seller provided Idaho Power an acceptable Engineer's Certificate dated August 31, 2004. Idaho Power will accept this previously provided Engineer's Certification to satisfy this requirement.

4.1.5 Insurance – Seller shall submit written proof to Idaho Power of all insurance required in Article XVI.

4.1.6 Interconnection – Seller shall complete all interconnection modifications, upgrades or additions as specified in Appendix D of this Agreement.

4.1.7 Written Acceptance - Obtain written confirmation from Idaho Power that all conditions to acceptance of energy have been fulfilled. Such written confirmation shall not be unreasonably withheld by Idaho Power.

ARTICLE V: TERM AND OPERATION DATE

5.1 Term - Subject to the provisions of paragraph 5.2 below, this Agreement shall become effective as of the date of this Agreement and shall continue in full force and effect for a period of seven (7) Contract Years from the Operation Date.

5.2 Operation Date – The Operation Date shall be March 1, 2006 contingent upon all requirements of Article IV being completed and accepted by Idaho Power Company no later than March 1, 2006.

ARTICLE VI: PURCHASE AND SALE OF NET ENERGY

6.1 Delivery and Acceptance of Net Energy - Except when either Party's performance is excused as provided herein, Idaho Power will purchase and Seller will sell all of the Net Energy to Idaho Power at the Point of Delivery. All Inadvertent Energy produced by the Facility will also be delivered by the Seller to Idaho Power at the Point of Delivery. At no time will the total amount of Net Energy and/or Inadvertent Energy produced by the Facility and delivered by the Seller to the Point of Delivery exceed the Maximum Capacity Amount.

6.2 Net Energy Amounts - Seller intends to produce and deliver Net Energy in the following monthly amounts:

6.2.1 Initial Year Monthly Net Energy Amounts:

	Month	kWh
	March	5,669,280
Season 1	April	5,486,400
	May	5,669,280
	July	6,233,232
	August	6,233,232
Season 2	November	5,486,400

	December	5,669,280
Season 3	June	2,432,819
	September	6,032,160
	October	5,669,280
	January	5,669,280
	February	5,120,640

6.2.2 Ongoing Monthly Net Energy Amounts - Seller shall initially provide Idaho Power with one year of monthly generation estimates (Initial Year Monthly Net Energy Amounts) and beginning at the end of month nine and every three months thereafter provide Idaho Power with an additional three months of forward generation estimates. This information will be provided to Idaho Power by written notice in accordance with paragraph 29.1, no later than 5:00 PM of the 5th day following the end of the previous month. If the Seller does not provide the Ongoing Monthly Net Energy amounts in a timely manner, Idaho Power will use the most recent 3 months of the Initial Year Monthly Net Energy Amounts specified in paragraph 6.2.1 for the next 3 months of monthly Net Energy amounts.

6.2.3 Seller's Adjustment of Net Energy Amount –

6.2.3.1 No later than the Operation Date, by written notice given to Idaho Power in accordance with paragraph 29.1, the Seller may revise all of the previously provided Initial Year Monthly Net Energy Amounts.

6.2.3.2 Beginning with the end of the 3rd month after the Operation Date and at the end of every third month thereafter: (1) the Seller may not revise the immediate next three months of previously provided Net Energy Amounts, (2) but by written notice given to Idaho Power in accordance with paragraph 29.1, no later than 5:00 PM of the 5th day following the end of the previous month, the Seller may revise all other previously provided Net Energy Amounts. Failure to provide timely written notice of changed amounts will be deemed to be an election of no change.

6.2.4 Idaho Power Adjustment of Net Energy Amount – If Idaho Power is excused from accepting the Seller's Net Energy as specified in paragraph 14.2.1 or if the Seller declares a Suspension of Energy Deliveries as specified in paragraph 14.3.1 and the Seller's declared Suspension of Energy Deliveries is accepted by Idaho Power, the Net Energy Amount as specified in paragraph 6.2 for the specific month in which the reduction or suspension under paragraph 14.2.1 or 14.3.1 occurs will be reduced in accordance with the following:

Where:

NEA = Current Month's Net Energy Amount (Paragraph 6.2)

SGU =

a.) If Idaho Power is excused from accepting the Seller's Net Energy as specified in paragraph 14.2.1 this value will be equal to the percentage of curtailment as specified by Idaho Power multiplied by the TGU as defined below.

b.) If the Seller declares a Suspension of Energy Deliveries as specified in paragraph 14.3.1 this value will be the sum of the individual generation units size ratings as specified in Appendix B that are impacted by the circumstances causing the Seller to declare a Suspension of Energy Deliveries.

TGU = Sum of all of the individual generator ratings of the generation units at this Facility as specified in Appendix B of this agreement.

RSH = Actual hours the Facility's Net Energy deliveries were either reduced or suspended under paragraph 14.2.1 or 14.3.1

TH = Actual total hours in the current month

Resulting formula being:

$$\text{Adjusted Net Energy Amount} = NEA - \left(\left(\frac{SGU}{TGU} \times NEA \right) \times \left(\frac{RSH}{TH} \right) \right)$$

This Adjusted Net Energy Amount will be used in applicable Surplus Energy calculations for only the specific month in which Idaho Power was excused from accepting the Seller's Net Energy or the Seller declared a Suspension of Energy.

6.3 Unless excused by an event of Force Majeure, Seller's failure to deliver Net Energy in any Contract Year in an amount equal to at least ten percent (10%) of the sum of the Initial Year Net Energy Amounts as specified in paragraph 6.2 shall constitute an event of default.

ARTICLE VII: PURCHASE PRICE AND METHOD OF PAYMENT

7.1 Net Energy Purchase Price – For all Net Energy, Idaho Power will pay the non-levelized energy price in accordance with Commission Order 29646 with seasonalization factors applied:

Year	Season 1 - (73.50 %) Mills/kWh	Season 2 - (120.00 %) Mills/kWh	Season 3 - (100.00 %) Mills/kWh
2006	37.85	61.80	51.50
2007	38.73	63.23	52.69
2008	39.62	64.68	53.90
2009	40.53	66.17	55.14
2010	41.46	67.69	56.41
2011	42.42	69.25	57.71
2012	43.39	70.85	59.04

7.2 Surplus Energy Price - For all Surplus Energy, Idaho Power shall pay to the Seller the current month's Market Energy Cost or the Net Energy Purchase Price specified in paragraph 7.1, whichever is lower.

7.3 Inadvertent Energy –

7.3.1 Inadvertent Energy is electric energy produced by the Facility, expressed in kWh, which the Seller delivers to Idaho Power at the Point of Delivery that exceeds 10,000 kW multiplied by the hours in the specific month in which the energy was delivered. (For example January contains 744 hours. 744 hours times 10,000 kW = 7,440,000 kWh. Energy delivered in January in excess of 7,440, 000 kWh in this example would be Inadvertent Energy.)

7.3.2 Although Seller intends to design and operate the Facility to generate no more than 10 average MW and therefore does not intend to generate Inadvertent Energy, Idaho Power will accept Inadvertent Energy that does not exceed the Maximum Capacity Amount but will not purchase or pay for Inadvertent Energy

7.4 Payment Due Date – Energy payments to the Seller will be disbursed within 30 days of the date which Idaho Power receives and accepts the documentation of the monthly Net Energy and Inadvertent Energy actually produced by the Seller's Facility and delivered to Idaho Power as specified in Appendix A.

7.5 Continuing Jurisdiction of the Commission –This Agreement is a special contract and, as such, the rates, terms and conditions contained in this Agreement will be construed in accordance with Idaho Power Company v. Idaho Public Utilities Commission and Afton Energy, Inc., 107 Idaho 781, 693 P.2d 427 (1984); Idaho Power Company v. Idaho Public Utilities Commission, 107 Idaho 1122, 695 P.2d 1 261 (1985); Afton Energy, Inc. v. Idaho Power Company, 111 Idaho 925, 729 P.2d 400 (1986); Section 210 of the Public Utilities Regulatory Policies Act of 1978 and 18 CFR §292.303-308.

ARTICLE VIII: ENVIRONMENTAL ATTRIBUTES

8.1 Idaho Power waives any claim to ownership of Environmental Attributes. Environmental Attributes include, but are not limited to, Green Tags, Green Certificates, Renewable Energy Credits (RECs) and Tradable Renewable Certificates (TRCs) directly associated with the production of energy from the Seller's Facility.

ARTICLE IX: FACILITY AND INTERCONNECTION

9.1 Design of Facility - This Facility is interconnected to Idaho Power and is selling energy to Idaho Power as a Qualifying Facility in accordance with a Firm Energy Sales agreement dated March 1, 2004. In this previous agreement, Seller was required to design, construct, install, own, operate and maintain the Facility and any Seller-owned Interconnection Facilities so as to allow safe and reliable generation and delivery of electric energy to Idaho Power for the full term of the Agreement. Seller will be required to maintain these same standards in the on-going operations of this facility for the term of this Agreement.

9.2 Interconnection Facilities - This Facility is interconnected to Idaho Power and is selling energy to

Idaho Power as a Qualifying Facility in accordance with a Firm Energy Sales agreement dated March 1, 2004. Idaho Power has reviewed the existing Interconnection Facilities and has identified specific items that will require modification, upgrades or additions to the existing equipment. These items are documented in Appendix D of this agreement. The Seller will be responsible to complete the modifications, upgrades or additions as specified in Appendix D. All costs of all items identified within Appendix D and payment to Idaho Power will be in accordance with Schedule 72.

ARTICLE X: DISCONNECTION EQUIPMENT

10.1 This Facility is interconnected to Idaho Power and is selling energy to Idaho Power as a Qualifying Facility in accordance with a Firm Energy Sales agreement dated March 1, 2004. Idaho Power has reviewed the existing Disconnection Equipment and has identified specific items that will require modification, upgrades or additions to the existing equipment. These items are documented in Appendix D of this agreement. The Seller will be responsible to complete the modifications, upgrades or additions as specified in Appendix D. All costs of all items identified within Appendix D and payment to Idaho Power will be in accordance with Schedule 72.

ARTICLE XI: METERING AND TELEMETRY

11.1 Metering - This Facility is interconnected to Idaho Power and is selling energy to Idaho Power as a Qualifying Facility in accordance with a Firm Energy Sales agreement dated March 1, 2004. Idaho Power has reviewed the Metering and Telemetry and has identified specific items that will require modification, upgrades or additions to the existing equipment. These items are documented in Appendix D of this agreement. The Seller will be responsible to complete the modifications, upgrades or additions as specified in Appendix D. All costs of all items identified within Appendix D and payment to Idaho Power will be in accordance with Schedule 72. All meters used to determine the billing hereunder shall be sealed and the seals shall be broken only by Idaho Power when the meters are to be inspected, tested or adjusted.

11.1.1 Meter Inspection - Idaho Power shall inspect and test all meters upon their Installation and at least once every four (4) years thereafter. If requested by Seller, Idaho Power shall make a special inspection or test of a meter and Seller shall pay the reasonable costs of such special inspection. Both Parties shall be notified of the time when any inspection or test shall take place, and each Party may have representatives present at the test or inspection. If a meter is found to be inaccurate or defective, it shall be adjusted, repaired or replaced, at Idaho Power's expense in order to provide accurate metering. If a meter fails to register, or if the measurement made by a meter during a test varies by more than two percent (2%) from the measurement made by the standard meter used in the test, adjustment (either upward or downward) to the payments Seller has received shall be made to correct those payments affected by the inaccurate meter for the actual period during which inaccurate measurements were made. If the actual period cannot be determined, corrections to the payments will be based on the shorter of (1) a period equal to one-half the time from the date of the last previous test of the meter to the date of the test which established the inaccuracy of the meter; or (2) six (6) months.

11.2 Telemetry – Metering, communications and telemetry equipment is required which is capable of providing Idaho Power with continuous instantaneous telemetry of Seller's net generation to Idaho Power's Designated Dispatch Facility. This Facility is interconnected to Idaho Power and is selling energy to Idaho Power as a Qualifying Facility in accordance with a Firm Energy Sales agreement dated March 1, 2004. Idaho Power has reviewed the Telemetry Equipment and has identified specific items that will require modification, upgrades or additions to the existing equipment in order for the parties to perform under this agreement. These items are documented in Appendix D of this agreement. The Seller will be responsible to complete the modifications, upgrades or additions as specified in Appendix D. All costs of all items identified within Appendix D and payment to Idaho Power will be in accordance with Schedule 72.

ARTICLE XII - RECORDS

12.1 Maintenance of Records - Seller shall maintain at the Facility or such other location mutually acceptable to the Parties adequate total generation, Net Energy, Station Use, Inadvertent Energy and maximum generation (kW) records in a form and content recommended by Idaho Power.

12.2 Inspection - Either Party, after reasonable notice to the other Party, shall have the right, during normal business hours, to inspect and audit any or all generation, Net Energy, Station Use, Inadvertent Energy and maximum generation (kW) records pertaining to the Seller's Facility.

ARTICLE XIII - PROTECTION

13.1 This Facility is interconnected to Idaho Power and is selling energy to Idaho Power as a Qualifying Facility in accordance with a Firm Energy Sales agreement dated March 1, 2004. Idaho Power has reviewed the existing Protection equipment and has identified specific items that will require modification, upgrades or additions to the existing equipment. These items are documented in Appendix D of this agreement. The Seller will be responsible to complete the modifications, upgrades or additions as specified in Appendix D. All costs of all items identified within Appendix D and payment to Idaho Power will be in accordance with Schedule 72. Seller shall provide and maintain adequate protective equipment sufficient to prevent damage to the Facility and Seller-furnished Interconnection Facilities. In some cases, some of Seller's protective relays will provide back-up protection for Idaho Power's facilities. In that event, Idaho Power will test such relays annually and Seller will pay the actual cost of such annual testing.

ARTICLE XIV - OPERATIONS

14 .1 Communications - Idaho Power and the Seller shall maintain appropriate operating communications through Idaho Power's Designated Dispatch Facility in accordance with Appendix A of this Agreement.

14 .2 Energy Acceptance –

14.2.1 Idaho Power shall be excused from accepting and paying for Net Energy or accepting

Inadvertent Energy produced by the Facility and delivered by the Seller to the Point of Delivery, if it is prevented from doing so by an event of Force Majeure, or if Idaho Power determines that curtailment, interruption or reduction of Net Energy or Inadvertent Energy deliveries is necessary because of line construction or maintenance requirements, emergencies, electrical system operating conditions on its system or as otherwise required by Prudent Electrical Practices. If, for reasons other than an event of Force Majeure, Idaho Power requires such a curtailment, interruption or reduction of Net Energy deliveries for a period that exceeds twenty (20) days, beginning with the twenty-first day of such interruption, curtailment or reduction, Seller will be deemed to be delivering Net Energy at a rate equivalent to the pro rata daily average of the amounts specified for the applicable month in paragraph 6.2. Idaho Power will notify Seller when the interruption, curtailment or reduction is terminated.

14.2.2 If, in the reasonable opinion of Idaho Power, Seller's operation of the Facility or Interconnection Facilities is unsafe or may otherwise adversely affect Idaho Power's equipment, personnel or service to its customers, Idaho Power may physically interrupt the flow of energy from the Facility as specified within Schedule 72 or take such other reasonable steps as Idaho Power deems appropriate.

14.2.3 Under no circumstances will the Seller deliver Net Energy and/or Inadvertent Energy from the Facility to the Point of Delivery in an amount that exceeds the Maximum Capacity Amount. Seller's failure to limit deliveries to the Maximum Capacity Amount will be a Material Breach of this Agreement.

14.3 <u>Seller Declared Suspension of Energy Deliveries</u>

14.3.1 If the Seller's Facility experiences a forced outage due to equipment failure which is not caused by an event of Force Majeure or by neglect, disrepair or lack of adequate preventative maintenance of the Seller's Facility, Seller may, after giving notice as provided in paragraph 14.3.2 below, temporarily suspend all deliveries of Net Energy to Idaho Power from the Facility or from individual generation unit(s) within the Facility impacted by the forced outage for a period of not less than 48 hours to correct the forced outage condition ("Declared Suspension of Energy Deliveries"). The Seller's Declared Suspension of Energy Deliveries will begin at the start of the next full hour following the Seller's telephone notification as specified in paragraph 14.3.2 and will continue for the time as specified (not less than 48 hours) in the written notification provided by the Seller. In the month(s) in which the Declared Suspension of Energy occurred, the Net Energy Amount will be adjusted as specified in paragraph 6.2.4.

14.3.2 If the Seller desires to initiate a Declared Suspension of Energy Deliveries as provided in paragraph 14.3.1, the Seller will notify the Designated Dispatch Facility by telephone. The beginning hour of the Declared Suspension of Energy Deliveries will be at the earliest the next full hour after making telephone contact with Idaho Power. The Seller will, within 24 hours after the telephone contact, provide Idaho Power a written notice in accordance with Article XXIX that will contain the beginning hour and duration of the Declared Suspension of Energy Deliveries and a description of the conditions that caused the Seller to initiate a Declared Suspension of Energy Deliveries. Idaho Power will review the documentation provided by the Seller to determine Idaho Power's acceptance of the described forced outage as qualifying for a Declared Suspension of Energy Deliveries as specified in paragraph 14.3.1. Idaho Power's acceptance of the Seller's forced outage as an acceptable forced outage will be based upon the clear documentation provided by the Seller that the forced outage is not due do an event of Force Majeure or by neglect, disrepair or lack of adequate preventative maintenance of the Seller's Facility.

14.4 Voltage Levels - Seller, in accordance with Prudent Electrical Practices shall minimize voltage fluctuations and maintain voltage levels acceptable to Idaho Power. Idaho Power may, in accordance with Prudent Electrical Practices, upon one hundred eighty (180) days' notice to the Seller, change its nominal operating voltage level by more than ten percent (10%) at the Point of Delivery, in which case Seller shall modify, at Idaho Power's expense, Seller's equipment as necessary to accommodate the modified nominal operating voltage level.

14.5 Generator Ramping - Idaho Power, in accordance with Prudent Electrical Practices, shall have the right to limit the rate that generation is changed at startup, during normal operation or following reconnection to Idaho Power's electrical system. Generation ramping may be required to permit Idaho Power's voltage regulation equipment time to respond to changes in power flow.

14.6 Scheduled Maintenance – On or before January 31 of each calendar year, Seller shall submit a written proposed maintenance schedule of significant Facility maintenance for that calendar year and Idaho Power and Seller shall mutually agree as to the acceptability of the proposed schedule. The Parties determination as to the acceptability of the Seller's timetable for scheduled maintenance will take into consideration Prudent Electrical Practices, Idaho Power system requirements and the Seller's preferred schedule. Neither Party shall unreasonably withhold acceptance of the proposed maintenance schedule.

14.7 Maintenance Coordination - The Seller and Idaho Power shall, to the extent practical, coordinate their respective line and Facility maintenance schedules such that they occur simultaneously.

14.8 Contact Prior to Curtailment - Idaho Power will make a reasonable attempt to contact the Seller prior to exercising its rights to curtail, interrupt or reduce deliveries from the Seller's Facility. Seller understands that in the case of emergency circumstances, real time operations of the electrical system, and/or unplanned events Idaho Power may not be able to provide notice to the Seller prior to interruption, curtailment, or reduction of electrical energy deliveries to Idaho Power.

ARTICLE XV: RELIABILITY MANAGEMENT SYSTEM

15.1 Purpose. In order to maintain the reliable operation of the transmission grid, the WECC Reliability Criteria Agreement sets forth reliability criteria adopted by the WECC to which this Seller and Idaho Power Company shall be required to comply. Seller acknowledges receipt of and understanding of the WECC Reliability Criteria Agreement and how it pertains to the Seller's facility.

15.2 Compliance. This Seller shall comply with the requirements of the WECC Reliability Criteria

Agreement, including the applicable WECC reliability criteria set forth in Section IV of Annex A thereof, and, in the event of failure to comply, Seller agrees to be subject to the sanctions applicable to such failure. Such sanctions shall be assessed pursuant to the procedures contained in the WECC Reliability Criteria Agreement. Each and all of the provisions of the WECC Reliability Criteria Agreement are hereby incorporated by reference into this Article 15 as though set forth fully herein, and Seller shall for all purposes be considered a Participant, and shall be entitled to all of the rights and privileges and be subject to all of the obligations of a Participant, under and in connection with the WECC Reliability Criteria Agreement, including, but not limited to the rights, privileges and obligations set forth in Sections 5, 6 and 10 of the WECC Reliability Criteria Agreement.

15.3 Payment of Sanctions. Seller shall be responsible for reimbursing Idaho Power Company for any monetary sanctions assessed against Idaho Power Company due to the action or inaction of the Seller by WECC pursuant to the WECC Reliability Criteria Agreement. Seller also shall be responsible for payment of any monetary sanction assessed against the Seller by WECC pursuant to the WECC Reliability Criteria Agreement. Any such payment shall be made pursuant to the procedures specified in the WECC Reliability Criteria Agreement.

15.4 Transfer of Control or Sale of Generation Facilities. In any sale or transfer of control of any generation facilities subject to this Agreement, Seller shall, as a condition of such sale or transfer, require the acquiring party or transferee with respect to the transferred facilities either to assume the obligations of the Seller with respect to this Agreement or to enter into an agreement with Idaho Power Company imposing on the acquiring party or transferee the same obligations applicable to the Seller pursuant to this Article 15.

15.5 Publication. Seller consents to the release by the WECC of information related to the Seller's compliance with this Agreement only in accordance with the WECC Reliability Criteria Agreement.

15.6 Third Parties. Except for the rights and obligations between the WECC and the Seller specified in this Article 15, this Agreement creates contractual rights and obligations solely between the

Parties. Nothing in this Agreement shall create, as between the Parties or with respect to the WECC: (a) any obligation or liability whatsoever (other than as expressly provided in this Agreement), or (b) any duty or standard of care whatsoever. In addition, nothing in this Agreement shall create any duty, liability or standard of care whatsoever as to any other party. Except for the rights, as a third-party beneficiary under this Article 15, of the WECC against the Seller for the Seller, no third party shall have any rights whatsoever with respect to enforcement of any provision of this Agreement. Idaho Power Company and the Seller expressly intend that the WECC is a third-party beneficiary to this Article 15, and the WECC shall have the right to seek to enforce against the Seller any provision of this Article 15, provided that specific performance shall be the sole remedy available to the WECC pursuant to Article 15 of this Agreement, and the Seller shall not be liable to the WECC pursuant to this Agreement for damages of any kind whatsoever (other than the payment of sanctions to the WECC, if so construed), whether direct, compensatory, special, indirect, consequential, or punitive.

15.7 Reserved Rights. Nothing in the Article 15 of this Agreement or the WECC Reliability Criteria Agreement shall affect the right of Idaho Power Company, subject to any necessary regulatory approval, to take such other measures to maintain reliability, including disconnection that Idaho Power Company may otherwise be entitled to take.

15.8 Termination of Article 15. Seller may terminate its obligations pursuant to this Article 15:

15.8.1 If after the effective date of this Article 15, the requirements of the WECC Reliability Criteria Agreement applicable to the Seller are amended so as to adversely affect the Seller, provided that the Seller gives fifteen (15) days' notice of such termination to Idaho Power Company and WECC within forty-five (45) days of the date of issuance of a Commission order accepting such amendment for filing, provided further that the forty-five (45) day period within which notice of termination is required may be extended by the Seller for an additional forty-five (45) days if the Seller gives written notice to Idaho Power Company of such requested extension within the initial forty-five (45) day period; or

15.8.2 For any reason on one year's written notice to Idaho Power Company and the WECC.

ARTICLE XVI: INDEMNIFICATION AND INSURANCE

16.1 Indemnification - Each Party shall agree to hold harmless and to indemnify the other Party, its officers, agents, affiliates, subsidiaries, parent company and employees against all loss, damage, expense and liability to third persons for injury to or death of person or injury to property, proximately caused by the indemnifying Party's construction, ownership, operation or maintenance of, or by failure of, any of such Party's works or facilities used in connection with this Agreement. The indemnifying Party shall, on the other Party's request, defend any suit asserting a claim covered by this indemnity. The indemnifying Party shall pay all costs, including reasonable attorney fees that may be incurred by the other Party in enforcing this indemnity.

16.2 Insurance - During the term of this Agreement, Seller shall secure and continuously carry the following insurance coverage:

16.2.1 Comprehensive General Liability Insurance for both bodily injury and property damage with limits of $2,000,000 each occurrence, combined single limit. The deductible for such insurance shall be consistent with current Insurance Industry Utility practices for similar property. Seller will be responsible for any deductible applicable to losses covered by this insurance.

16.2.2 The above insurance coverage shall be placed with an insurance company with an A.M. Best Company rating of A- or better and shall include:

(a) An endorsement naming Idaho Power as an additional insured and loss payee as applicable; and

(b) A provision stating that such policy shall not be canceled or the limits of liability reduced without sixty (60) days' prior written notice to Idaho Power.

16.3 Seller to Provide Certificate of Insurance - As required in paragraph 4.1.5 herein and annually thereafter, Seller shall furnish Idaho Power a certificate of insurance, together with the endorsements required therein, evidencing the coverage as set forth above.

16.4 Seller to Notify Idaho Power of Loss of Coverage - If the insurance coverage required by paragraph 16.2 shall lapse for any reason, Seller will immediately notify Idaho Power in writing. The notice will advise Idaho Power of the specific reason for the lapse and the steps Seller is taking to reinstate the coverage. Failure to provide this notice and to expeditiously reinstate or replace the coverage will constitute a Material Breach of this Agreement.

ARTICLE XVII. FORCE MAJEURE

17.1 As used in this Agreement, "Force Majeure" or "an event of Force Majeure" means any cause beyond the control of the Seller or of Idaho Power which, despite the exercise of due diligence, such Party is unable to prevent or overcome. Force Majeure includes, but is not limited to, acts of God, fire, flood, storms, wars, hostilities, civil strife, strikes and other labor disturbances, earthquakes, fires, lightning, epidemics, sabotage, or changes in law or regulation occurring after the Operation Date, which, by the exercise of reasonable foresight such party could not reasonably have been expected to avoid and by the exercise of due diligence, it shall be unable to overcome. If either Party is rendered wholly or in part unable to perform its obligations under this Agreement because of an event of Force Majeure, both Parties shall be excused from whatever performance is affected by the event of Force Majeure, provided that:

(1) The non-performing Party shall, as soon as is reasonably possible after the occurrence of the Force Majeure, give the other Party written notice describing the particulars of the occurrence.

(2) The suspension of performance shall be of no greater scope and of no longer duration than is required by the event of Force Majeure.

(3) No obligations of either Party which arose before the occurrence causing the suspension of performance and which could and should have been fully performed before such occurrence shall be excused as a result of such occurrence.

ARTICLE XVIII: LAND RIGHTS

18.1 Seller to Provide Access - Seller hereby grants to Idaho Power for the term of this Agreement all necessary rights-of-way and easements to install, operate, maintain, replace, and remove Idaho Power's Metering Equipment, Interconnection Equipment, Disconnection Equipment, Protection Equipment and other Special Facilities necessary or useful to this Agreement, including adequate and continuing access rights on property of Seller. Seller warrants that it has procured sufficient easements and rights-of-way from third parties so as to provide Idaho Power with the access described above. All documents granting such easements or rights-of-way shall be subject to Idaho Power's approval and in recordable form.

18.2 Use of Public Rights-of-Way - The Parties agree that it is necessary to avoid the adverse environmental and operating impacts that would occur as a result of duplicate electric lines being constructed in close proximity. Therefore, subject to Idaho Power's compliance with paragraph 18.4, Seller agrees that should Seller seek and receive from any local, state or federal governmental body the right to erect, construct and maintain Seller-furnished Interconnection Facilities upon, along and over any and all public roads, streets and highways, then the use by Seller of such public right-of-way shall be subordinate to any future use by Idaho Power of such public right-of-way for construction and/or maintenance of electric distribution and transmission facilities and Idaho Power may claim use of such public right-of-way for such purposes at any time. Except as required by paragraph 18.4, Idaho Power shall not be required to compensate Seller for exercising its rights under this paragraph 18.2.

18.3 Joint Use of Facilities - Subject to Idaho Power's compliance with paragraph 18.4, Idaho Power may use and attach its distribution and/or transmission facilities to Seller's Interconnection Facilities, may reconstruct Seller's Interconnection Facilities to accommodate Idaho Power's usage or Idaho Power may construct its own distribution or transmission facilities along, over and above any public right-of-way acquired from Seller pursuant to paragraph 18.2, attaching Seller's Interconnection Facilities to such newly constructed facilities. Except as required by paragraph 18.4, Idaho Power shall not be required to compensate Seller for exercising its rights under this paragraph 18.3.

18.4 Conditions of Use - It is the intention of the Parties that the Seller be left in substantially the same condition, both financially and electrically, as Seller existed prior to Idaho Power's exercising its rights under this Article XVIII. Therefore, the Parties agree that the exercise by Idaho Power of any of the rights enumerated in paragraphs 18.2 and 18.3 shall: (1) comply with all applicable laws, codes and Prudent Electrical Practices, (2) equitably share the costs of installing, owning and operating jointly used facilities and rights-of-way. If the Parties are unable to agree on the method of apportioning these costs, the dispute will be submitted to the Commission for resolution and the decision of the Commission will be binding on the Parties, and (3) shall provide Seller with an interconnection to Idaho Power's system of equal capacity and durability as existed prior to Idaho Power exercising its rights under this Article XVIII.

ARTICLE XIX: LIABILITY; DEDICATION

19.1 Nothing in this Agreement shall be construed to create any duty to, any standard of care with reference to, or any liability to any person not a Party to this Agreement. No undertaking by one Party to the other under any provision of this Agreement shall constitute the dedication of that Party's system or any portion thereof to the other Party or to the public or affect the status of Idaho Power as an independent public utility corporation or Seller as an independent individual or entity.

ARTICLE XX: SEVERAL OBLIGATIONS

20.1 Except where specifically stated in this Agreement to be otherwise, the duties, obligations and liabilities of the Parties are intended to be several and not joint or collective. Nothing contained in this Agreement shall ever be construed to create an association, trust, partnership or joint venture or impose a trust or partnership duty, obligation or liability on or with regard to either Party. Each Party shall be individually and severally liable for its own obligations under this Agreement.

ARTICLE XXI: WAIVER

21.1 Any waiver at any time by either Party of its rights with respect to a default under this Agreement or with respect to any other matters arising in connection with this Agreement shall not be deemed a waiver with respect to any subsequent default or other matter.

ARTICLE XXII: CHOICE OF LAWS AND VENUE

22.1 This Agreement shall be construed and interpreted in accordance with the laws of the State of Idaho without reference to its choice of law provisions.

22.2 Venue for any litigation arising out of or related to this Agreement will lie in the District Court of the Fourth Judicial District of Idaho in and for the County of Ada.

ARTICLE XXIII: DISPUTES AND DEFAULT

23.1 Disputes - All disputes related to or arising under this Agreement, including, but not limited to, the interpretation of the terms and conditions of this Agreement, will be submitted to the Commission for resolution.

23.2 Notice of Default -

23.2.1 Defaults. If either Party fails to perform any of the terms or conditions of this Agreement (an "event of default"), the nondefaulting Party shall cause notice in writing to be given to the defaulting Party, specifying the manner in which such default occurred. If the defaulting Party shall fail to cure such default within the sixty (60) days after service of such notice, or if the defaulting Party reasonably demonstrates to the other Party that the default can be cured within a commercially reasonable time but not within such sixty (60) day period and then fails to diligently pursue such cure, then, the nondefaulting Party may, at its option, terminate this Agreement and/or pursue its legal or equitable remedies.

23.2.2 Material Breaches – The notice and cure provisions in paragraph 23.2.1 do not apply to defaults identified in this Agreement as Material Breaches. Material Breaches must be cured as expeditiously as possible following occurrence of the breach.

23.3 Security for Performance - Prior to the Operation Date and thereafter for the full term of this Agreement, Seller will provide Idaho Power with the following:

23.3.1 Insurance - Evidence of compliance with the provisions of paragraph 16.2. If Seller fails to comply, such failure will be a Material Breach and may only be cured by Seller supplying evidence that the required insurance coverage has been replaced or reinstated;

23.3.2 Engineer's Certifications – Within 30 days of August 31, 2007 and then every three (3) years after August 31, 2007, Seller will supply Idaho Power with a Certification of Ongoing Operations and Maintenance (O & M) from a Registered Professional Engineer licensed in the State of Idaho, which Certification of Ongoing O & M shall be in the form specified in Appendix C. Seller's failure to supply the required certificate will be an event of default. Such a default may only be cured by Seller providing the required certificate; and

23.3.3 Licenses and Permits - During the full term of this Agreement, Seller shall maintain compliance with all permits and licenses described in paragraph 4.1.1 of this Agreement. In addition, Seller will supply Idaho Power with copies of any new or additional permits or licenses. At least every fifth Contract Year, Seller will update the documentation described in Paragraph 4.1.1. If at any time Seller fails to maintain compliance with the permits and licenses described in paragraph 4.1.1 or to provide the documentation required by this paragraph, such failure will be an event of default and may only be cured by Seller submitting to Idaho Power evidence of compliance from the permitting agency.

ARTICLE XXIV: GOVERNMENTAL AUTHORIZATION

24.1 This Agreement is subject to the jurisdiction of those governmental agencies having control over either Party of this Agreement.

ARTICLE XXV: COMMISSION ORDER

25.1 This Agreement shall become finally effective upon the Commission's approval of all terms and provisions hereof without change or condition and declaration that all payments to be made to Seller hereunder shall be allowed as prudently incurred expenses for ratemaking purposes.

ARTICLE XXVI: SUCCESSORS AND ASSIGNS

26.1 This Agreement and all of the terms and provisions hereof shall be binding upon and inure to the benefit of the respective successors and assigns of the Parties hereto, except that no assignment hereof by either Party shall become effective without the written consent of both Parties being first obtained. Such consent shall not be unreasonably withheld. Notwithstanding the foregoing, any party which Idaho Power may consolidate, or into which it may merge, or to which it may convey or transfer substantially all of its electric utility assets, shall automatically, without further act, and without need of consent or approval by the Seller, succeed to all of Idaho Power's rights, obligations and interests under this Agreement. This article shall not prevent a financing entity with recorded or secured rights from exercising all rights and remedies available to it under law or contract. Idaho Power shall have the right to be notified by the financing entity that it is exercising such rights or remedies.

ARTICLE XXVII: MODIFICATION

27.1 No modification to this Agreement shall be valid unless it is in writing and signed by both Parties and subsequently approved by the Commission.

ARTICLE XXVIII: TAXES

28.1 Each Party shall pay before delinquency all taxes and other governmental charges which, if failed to be paid when due, could result in a lien upon the Facility or the Interconnection Facilities.

ARTICLE XXIX: NOTICES

29.1 All written notices under this agreement shall be directed as follows and shall be considered delivered when deposited in the U. S. Mail, first-class postage prepaid, as follows:

To Seller:

Original document to:

J R Simplot Company
Attn: Corporate Secretary
P O Box 27
Boise, Idaho 83707

Copy of document to:

J R Simplot Company
Attn: David Hawk
P O Box 27
Boise, Idaho 83707

To Idaho Power:

Original document to:

Vice President, Power Supply
Idaho Power Company
P O Box 70
Boise, Idaho 83707

Copy of document to:

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

ARTICLE XXX: ADDITIONAL TERMS AND CONDITIONS

30.1 This Agreement includes the following appendices, which are attached hereto and included by reference:

Appendix A	-	Generation Scheduling and Reporting
Appendix B	-	Facility and Point of Delivery
Appendix C	-	Engineer's Certifications
Appendix D	-	Modifications, Upgrades and Additions

ARTICLE XXXI: SEVERABILITY

31.1 The invalidity or unenforceability of any term or provision of this Agreement shall not affect the validity or enforceability of any other terms or provisions and this Agreement shall be construed in all other respects as if the invalid or unenforceable term or provision were omitted.

ARTICLE XXXII: COUNTERPARTS

32.1 This Agreement may be executed in two or more counterparts, each of which shall be deemed an original but all of which together shall constitute one and the same instrument.

ARTICLE XXXIII: ENTIRE AGREEMENT

33.1 This Agreement constitutes the entire Agreement of the Parties concerning the subject matter hereof and supersedes all prior or contemporaneous oral or written agreements between the Parties concerning the subject matter hereof.

IN WITNESS WHEREOF, The Parties hereto have caused this Agreement to be executed in their respective names on the dates set forth below:

Idaho Power Company	J R Simplot Company
By J. C. Miller	By M. W. Hunt
Jim C. Miller, Sr. Vice President, Power Supply	
Dated 2/8/06	Dated 2/6/06
"Idaho Power"	"Seller"

APPENDIX A

A –1 MONTHLY POWER PRODUCTION AND SWITCHING REPORT

At the end of each month the following required documentation will be submitted to:

Idaho Power Company
Attn: Cogeneration and Small Power Production
P 0 Box 70
Boise, Idaho 83707

The Meter readings required on this report will be the reading on the Idaho Power Meter Equipment measuring the Facility's total energy production, Station Usage, Inadvertent Energy delivered to Idaho Power and the maximum generated energy (kW) as recorded on the Meter Equipment and/or any other required energy measurements to adequately administer this Agreement.

Idaho Power Company

Cogeneration and Small Power Production

MONTHLY POWER PRODUCTION AND SWITCHING REPORT

Month ______________ **Year** ______________

Project Name ______________________________ **Project Number:** ______________

Address ______________________________ **Phone Number:** ______________

City ______________ **State** ______ **Zip** ______________

	Facility Output	Station Usage	Station Usage
Meter Number:			
End of Month kWh Meter Reading:			
Beginning of Month kWh Meter:			
Difference:			
Times Meter Constant:			
kWh for the Month:	-	-	=
Metered Demand:			

Metered Maximum Generation
______ kW

Net Generation

Breaker Opening Record

Date	Time	Meter

*	Reason

Breaker Closing Record

Date	Time	Meter

*	Breaker Opening Reason Codes
1	Lack of Adequate Prime Mover
2	Forced Outage of Facility
3	Disturbance of IPCo System
4	Scheduled Maintenance
5	Testing of Protection Systems
6	Cause Unknown
7	Other (Explain)

I hereby certify that the above meter readings are true and correct as of Midnight on the last day of the above month and that the switching record is accurate and complete as required by the Firm Energy Sales Agreement to which I am a Party.

______________________________ **Signature** ______________ **Date**

A-2 ROUTINE REPORTING

Idaho Power Contact Information

Daily Energy Production Reporting

Call daily by 10 a.m., 1-800-356-4328 or 1-800-635-1093 and leave the following information:

- Project Identification - Project Name and Project Number
- Current Meter Reading
- Estimated Generation for the current day
- Estimated Generation for the next day

Planned and Unplanned Project outages

Call 1-800-345-1319 and leave the following information:

- Project Identification - Project Name and Project Number
- Approximate time outage occurred
- Estimated day and time of project coming back online

Seller's Contact Information

24-Hour Project Operational Contact

Name: ____________________
Telephone Number: ____________________
Cell Phone: ____________________

Project On-site Contact information

Telephone Number: ____________________

APPENDIX B

FACILITY AND POINT OF DELIVERY

PROJECT NO. 41866112

SIMPLOT POCATELLO

B-1 DESCRIPTION OF FACILITY

The Seller's Facility is described as one General Electric synchronous generator with a three-phase nameplate rating of 18.75 MVA at 13.2 kV three phase, 60 hertz, driven by a steam turbine.

B-2 LOCATION OF FACILITY

The Facility is located in the South Half of Section 7, Township 6 South, Range 34 East, Boise Meridian, Power County, Idaho.

B-3 MAXIMUM CAPACITY AMOUNT: This value will be 12 MW. This value is the maximum energy (MW) that potentially could be delivered by the Seller's Facility to the Idaho Power electrical system at any moment in time.

B-4 POINT OF DELIVERY

The Point of Delivery of energy from the Seller to Idaho Power is the 12.47 kV bushings of the Idaho Power owned phosphate substation metalclad vacuum breaker connected to the Simplot three-phase transformer bank. This isolation transformer bank, which consists of three single phase 5000 kVA/6250 kVA transformers, is connected 12.47 kV Delta to 13.09/7.56 kV grounded wye three phase, and the underground primary conductors connecting the transformer to the metalclad is owned by Simplot.

B-5 METERING

The Metering Equipment is located at Don Substation on the Don 015 metalclad bus and consists of potential and current transformers, and a Scientific Columbus JEM 2 electronic bi—directional demand meter. The meter registers kilowatt-hours and kilowatts of demand.

B-6 SPECIAL FACILITIES

The completion of the fifth distribution feeder bay including metalclad and metering at Don Substation, installation of new substation 12.47 kV underground getaway cables, construction of a section of overhead three phase 12.47 kV distribution feeder, and the installation of a section of underground three phase 12.47 kV distribution feeder, has been provided by Idaho Power as Special Facilities.

B-7 DISCONNECTION EQUIPMENT

Disconnection Equipment is required to insure that the Seller's Facility will be disconnected from Idaho Power's system in the event of a disturbance on either Idaho Power's system or the Seller's Facility. This equipment is for the protection of Idaho Power's equipment only. Idaho Power has installed the protective equipment in a new substation to be called Phosphate. This equipment consists of a metal clad vacuum breaker, potential transformers, and relaying and associated wiring. Idaho Power will rely on generator emergency batteries and certain generator fault relays for fault detection. Idaho Power did connect and test the equipment prior to the operation of the facility. The total cost of the Disconnection Equipment, connection and testing has been reimbursed to Idaho Power by the Seller.

B-8 COSTS

The total cost of Special Facilities and metering was $214,989. The total cost of the Disconnecting Equipment was $84,052. The total cost paid by the Seller was $299,041. In addition to the installation and construction charges above, during the term of the Agreement Seller will pay Idaho Power an operation and maintenance charge of the sum of the following:

Original Equipment - This Facility has been interconnected and delivering energy to Idaho Power Company under previous agreements. The monthly Schedule 72 operations and maintenance expense in regards to the equipment originally installed at a total cost of $299,041 will continue on the same operations and maintenance schedule as specified in Schedule 72 based upon the original installation date of this equipment. Thus, for the calendar year from January 1, 2006 through December 31, 2006 Contract Year, the Schedule 72 Contract Year to be referenced to the Schedule 72 Operations and Maintenance table will be Contract Year 16, January 1, 2007 through December 31, 2007 Contract Year, the Schedule 72 Contract Year to be referenced to the Schedule 72 Operations and Maintenance table will be Contract Year 17 and so on for the term of the this Agreement.

Additional Equipment – any new equipment installations beyond the scope of routine maintenance of the Original Equipment will considered to be Additional Equipment and the Schedule 72 Contract year will be determined based upon the completed installation date of the Additional Equipment. The complete installed cost of the Additional Equipment will be the bases that the appropriate Schedule 72 Operations and Maintenance percentage shall be applied.

B-9 SALVAGE

No later than sixty (60) days after the termination or expiration of this Agreement, Idaho Power will prepare and forward to Seller an estimate of the remaining value of those Idaho Power furnished Interconnection Facilities described in this Appendix, less the cost of removal and transfer to Idaho Power's nearest warehouse. If the Interconnection Facilities will be removed, Idaho Power may then be invoiced by Seller for the net salvage value estimated by Idaho Power for the interconnection facilities and shall pay such amount to Seller within thirty (30) days after receipt of said invoice.

APPENDIX C
ENGINEER'S CERTIFICATION

OF

OPERATIONS & MAINTENANCE POLICY

The undersigned ______________________________, on behalf of himself and ______________________________, hereinafter collectively referred to as "Engineer," hereby states and certifies to the Seller as follows:

1. That Engineer is a Licensed Professional Engineer in good standing in the State of Idaho.

2. That Engineer has reviewed the Energy Sales Agreement, hereinafter "Agreement," between Idaho Power as Buyer, and ______________________________as Seller, dated ____________________.

3. That the cogeneration or small power production project which is the subject of the Agreement and this Statement is identified as IPCo Facility No. ______________ and is hereinafter referred to as the "Project."

4. That the Project, which is commonly known as the ______________________, is located in Section ____ Township _______, Range _______, Boise Meridian, ____________ County, Idaho.

5. That Engineer recognizes that the Agreement provides for the Project to furnish electrical energy to Idaho Power for a twenty (20) year period.

6. That Engineer has substantial experience in the design, construction and operation of electric power plants of the same type as this Project.

7. That Engineer has no economic relationship to the Design Engineer of this Project.

8. That Engineer has reviewed and/or supervised the review of the Policy for Operation and Maintenance ("O&M") for this Project and it is his professional opinion that, provided said Project has been designed and built to appropriate standards, adherence to said O&M Policy will result in the

Project's producing at or near the design electrical output, efficiency and plant factor for a twenty (20) year period.

9. That Engineer recognizes that Idaho Power, in accordance with paragraph 5.2 of the Agreement, is relying on Engineer's representations and opinions contained in this Statement.

10. That Engineer certifies that the above statements are complete, true and accurate to the best of his knowledge and therefore sets his hand and seal below.

By ______________________________

(P.E. Stamp)

Date ______________________________

APPENDIX C

ENGINEER'S CERTIFICATION

OF

ONGOING OPERATIONS AND MAINTENANCE

The undersigned ______________________________, on behalf of himself and ______________________________ hereinafter collectively referred to as "Engineer," hereby states and certifies to the Seller as follows:

1. That Engineer is a Licensed Professional Engineer in good standing in the State of Idaho.

2. That Engineer has reviewed the Energy Sales Agreement, hereinafter "Agreement," between Idaho Power as Buyer, and ____________________as Seller, dated ____________________.

3. That the cogeneration or small power production project which is the subject of the Agreement and this Statement is identified as IPCo Facility No. __________ and hereinafter referred to as the "Project".

4. That the Project, which is commonly known as the ________________________ Project, is located at ________________________.

5. That Engineer recognizes that the Agreement provides for the Project to furnish electrical energy to Idaho Power for a twenty (20) year period.

6. That Engineer has substantial experience in the design, construction and operation of electric power plants of the same type as this Project.

7. That Engineer has no economic relationship to the Design Engineer of this Project.

8. That Engineer has made a physical inspection of said Project, its operations and maintenance records since the last previous certified inspection. It is Engineer's professional opinion, based on the Project's appearance, that its ongoing O&M has been substantially in accordance with said O&M Policy; that it is in reasonably good operating condition; and that if adherence to said O&M Policy continues, the Project will continue producing at or near its design electrical output, efficiency and plant factor for the remaining _____ years of the Agreement.

9. That Engineer recognizes that Idaho Power, in accordance with paragraph 5.2 of the Agreement, is relying on Engineer's representations and opinions contained in this Statement.

10. That Engineer certifies that the above statements are complete, true and accurate to the best of his knowledge and therefore sets his hand and seal below.

By ______________________________

(P.E. Stamp)

Date ________________________________

APPENDIX C

ENGINEER'S CERTIFICATION

OF

DESIGN & CONSTRUCTION ADEQUACY

The undersigned ______________________________, on behalf of himself and ________________________________, hereinafter collectively referred to as "Engineer", hereby states and certifies to Idaho Power as follows:

1. That Engineer is a Licensed Professional Engineer in good standing in the State of Idaho.

2. That Engineer has reviewed the Firm Energy Sales Agreement, hereinafter "Agreement", between Idaho Power as Buyer, and _________________________ as Seller, dated __________, ________________________.

3. That the cogeneration or small power production project, which is the subject of the Agreement and this Statement, is identified as IPCo Facility No ______________ and is hereinafter referred to as the "Project".

4. That the Project, which is commonly known as the ______________________ Project, is located in Section ______, Township ______, Range ______, Boise Meridian, _______ County, Idaho.

5. That Engineer recognizes that the Agreement provides for the Project to furnish electrical energy to Idaho Power for a ____________ (____) year period.

6. That Engineer has substantial experience in the design, construction and operation of electric power plants of the same type as this Project.

7. That Engineer has no economic relationship to the Design Engineer of this Project and has made the analysis of the plans and specifications independently.

8. That Engineer has reviewed the engineering design and construction of the Project, including the civil work, electrical work, generating equipment, prime mover conveyance system, Seller furnished Interconnection Facilities and other Project facilities and equipment.

9. That the Project has been constructed in accordance with said plans and specifications, all applicable codes and consistent with Prudent Electrical Practices as that term is described in the Agreement.

10. That the design and construction of the Project is such that with reasonable and prudent operation and maintenance practices by Seller, the Project is capable of performing in accordance with the terms of the Agreement and with Prudent Electrical Practices for a ________ (______) year period.

11. That Engineer recognizes that Idaho Power, in accordance with paragraph 5.2 of the Agreement, in interconnecting the Project with its system, is relying on Engineer's representations and opinions contained in this Statement.

12. That Engineer certifies that the above statements are complete, true and accurate to the best of his knowledge and therefore sets his hand and seal below.

By ______________________________

(P.E. Stamp)

Date ____________________________

APPENDIX D

MODIFICATIONS, UPGRADES AND ADDITIONS

PROJECT NO. 41866112

SIMPLOT POCATELLO

This Facility is interconnected to Idaho Power and is selling energy to Idaho Power as a Qualifying Facility in accordance with a Firm Energy Sales Agreement dated March 1, 2004, prior to that agreement this Facility was selling energy to Idaho Power as a Qualifying Facility in accordance with a Firm Energy Sales agreement dated January 24, 1991, first amendment of November 30, 1993 and second amendment dated February 23, 2001. The Interconnection Facilities, Disconnection Equipment, Metering Equipment, Telemetry Equipment and Protection Equipment were designed, installed, operated and maintained in accordance with these previous agreements.

Idaho Power has reviewed the existing Interconnection Facilities, Disconnection Equipment, Metering Equipment, Telemetry Equipment and Protection Equipment and listed below are specific modifications, upgrades and /or additions required for these facility to continue to deliver energy to Idaho Power at the Point of Delivery under this new Energy Sales Agreement. The Seller will be responsible to complete the modifications, upgrades or additions as specified in this Appendix D. All costs of all items identified within this Appendix D and payment to Idaho Power will be in accordance with Schedule 72.

D-1 INTERCONNECTION FACILITIES

Idaho Power has reviewed the existing Interconnection Facilities at the Sellers facility and finds that no upgrades, modifications or additions are required that the Seller would at this time be responsible for. If in the future, Prudent Electrical Practices, regulations, electrical codes or safety codes require upgrades, modifications or additions to the existing equipment, Idaho Power will notify the Seller of these requirements and the Seller will be responsible for all costs of all items identified and payment to Idaho Power will be in accordance with Schedule 72.

D-2 DISCONNECTION EQUIPMENT

Idaho Power has reviewed the existing Disconnection Equipment at the Sellers facility and finds that no upgrades, modifications or additions are required that the Seller would at this time be responsible for. If in the future, Prudent Electrical Practices, regulations, electrical codes or safety codes require upgrades, modifications or additions to the existing equipment, Idaho Power will notify the Seller of these requirements and the Seller will be responsible for all costs of all items identified and payment to Idaho Power will be in accordance with Schedule 72.

D-3 METERING EQUIPMENT

Idaho Power has reviewed the existing Metering Equipment at the Sellers facility and finds that no upgrades, modifications or additions are required that the Seller would at this time be responsible for. If in the future, Prudent Electrical Practices, regulations, electrical codes or safety codes require upgrades, modifications or additions to the existing equipment, Idaho Power will notify the Seller of these requirements and the Seller will be responsible for all costs of all items identified and payment to Idaho Power will be in accordance with Schedule 72.

D-4 TELEMETRY EQUIPMENT

Idaho Power has reviewed the existing Telemetry Equipment at the Sellers facility and finds that no upgrades, modifications or additions are required that the Seller would at this time be responsible for. If in the future, Prudent Electrical Practices, regulations, electrical codes or safety codes require upgrades, modifications or additions to the existing equipment, Idaho Power will notify the Seller of these requirements and the Seller will be responsible for all costs of all items identified and payment to Idaho Power will be in accordance with Schedule 72.

D-5 PROTECTION EQUIPMENT

Idaho Power has reviewed the existing Protection Equipment at the Sellers facility and finds that no upgrades, modifications or additions are required that the Seller would at this time be responsible for. If in the future, Prudent Electrical Practices, regulations, electrical codes or safety codes require upgrades, modifications or additions to the existing equipment, Idaho Power will notify the Seller of these requirements and the Seller will be responsible for all costs of all items identified and payment to Idaho Power will be in accordance with Schedule 72.

Facility Owned Protective Relays – The facility owns and operates several protective relays that provide protection to the Idaho Power System. As specified in paragraph 13.1 of this Agreement, when the Seller's protective relays provide protection for the Idaho Power system, Idaho Power annually tests these relays at the Seller' s expense. Historically, this testing has been accomplished by Idaho Power witnessing the Seller's annual tests of these relays. The Seller being responsible for costs of the tests and the cost of Idaho Power providing a witness to these tests. This arrangement has accommodated both parties in the past and will be continued until such time as either Idaho Power or the Seller request in writing a change in this testing procedure.

CASE NO. GNR-E-11-03

PETITION FOR RECONSIDERATION
OF J.R. SIMPLOT COMPANY AND CLEARWATER PAPER
CORPORATION

ATTACHMENT 3

Office of the Secretary
Service Date
January 15, 2004

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE JOINT PETITION OF AVISTA CORPORATION AND POTLATCH CORPORATION FOR APPROVAL OF A POWER PURCHASE AND SALE AGREEMENT	)	**CASE NO. AVU-E-03-7**
	)	**ORDER NO. 29418**

On August 25, 2003, Avista Corporation dba Avista Utilities (Avista) and Potlatch Corporation (Potlatch) filed a Joint Petition with the Idaho Public Utilities Commission (Commission) requesting an Order approving a submitted Power Purchase and Sale Agreement (Agreement) between Avista and Potlatch dated July 22, 2003. Potlatch operates a wood pulp, paperboard, tissue and wood product manufacturing facility in Lewiston, Idaho. Potlatch owns and operates four electric generators at the Lewiston plant that are capable of generating approximately 130 megawatts (MWs) of energy. The Potlatch electric generators are qualifying facilities (QFs) pursuant to the Public Utilities Regulatory Policies Act of 1978 (PURPA). Direct testimony of Avista supporting the Purchase and Sale Agreement was filed with the Commission on September 26, 2003. Also filed with the Commission on October 10, 2003 is a related Interconnection Agreement dated September 22, 2003.

The Commission in this Order approves the submitted Avista/Potlatch Power Purchase and Sale Agreement dated July 22, 2003. In doing so we find the contract terms, pricing, jurisdictional allocation and proposed recovery method to be reasonable and acceptable. The Commission in this Order approves a recovery method and authorizes the booking of Avista's power purchase costs in the Company's PCA deferral account. This Order has no immediate rate effect and does not change the tariff rates for other customers. Recovery of Potlatch power purchase costs by the Company will require a rate case or PCA filing.

Agreement

The submitted Power Purchase and Sale Agreement is for a ten-year term beginning July 1, 2003 and ending June 30, 2013. The Agreement is conditioned upon approval by the Commission of 1) a direct assignment to Avista's Idaho operations of all power purchase costs paid by Avista to Potlatch under the Purchase and Sale Agreement and 2) deferral and recovery of 100% of all power purchase costs paid by Avista to Potlatch under the Agreement to Avista's

Idaho Power Cost Adjustment (PCA) mechanism (Schedule 66) or otherwise recovered by Avista through base rates.

As recited in the Joint Petition of the parties, Avista will be the sole purchaser of Potlatch's generation and said purchase is intended to satisfy Avista's obligations under PURPA to purchase power from the qualifying facilities at the Lewiston plant. Avista will pay Potlatch $42.92 per MWh up to a maximum base generation amount of 543,120 MWh (544,608 during a leap year) generated by Potlatch during each July 1 through June 30 period (Operating Year) of the Agreement. This amount is equivalent to 62 average megawatts (aMW) and is referred to in the Agreement as the "Base Generation Amount." Amounts generated by Potlatch in excess of the maximum Base Generation Amount each Operating Year ("Excess Generation Amount") will either be purchased by Avista at 85% of the applicable Mid-Columbia Firm Index Price, with a price cap of $55 per MWh, or used by Potlatch to reduce its load requirements from Avista. The purchase of Potlatch's Excess Generation Amounts by Avista is limited to 43,800 MWh (5 aMW) each Operating Year. Excess Generation Amounts above this level would be used by Potlatch to serve its load requirements.

Additionally, it is noted that Potlatch has the capacity to generate additional amounts ("Incremental Generation Amounts") under certain circumstances. The Purchase and Sale Agreement provides for the purchase by Avista of Incremental Generation Amounts when it is mutually beneficial to both parties, under the terms and conditions specified in the Agreement.

As reflected in the Agreement, Avista will serve Potlatch's load requirements at Potlatch's Lewiston plant under its Extra Large General Service Schedule 25 rates, including the present Power Cost Adjustment (PCA) surcharge and all applicable rate adjustments, unless the Commission issues an Order in the future authorizing different billing rates.

Avista and Potlatch request that the Commission issue an Order approving the Purchase and Sale Agreement as a settlement of all known existing disputes between the parties, including without limitation, Case No. AVU-E-01-5 (In the matter of the Petition of Potlatch Corporation for an Order determining the terms and conditions of Potlatch's purchase of electricity from Avista Utilities) and Case No. AVU-E-02-8 (a Potlatch complaint alleging that Avista was refusing to purchase the cogeneration of Potlatch's PURPA qualifying facilities at its Lewiston plant).

On October 23, 2003, the Commission issued Notices of Joint Petition and Modified Procedure in Case No. AVU-E-03-7. The deadline for filing written comments was November 14, 2003. The reply deadline was November 28, 2003. Commission Staff was the only party to file comments. No reply comments were filed.

Staff Comments

Staff recommends that the Commission approve the submitted Power Purchase and Sale Agreement between Avista and Potlatch. Staff comments can be summarized as follows:

Proposed Price for Potlatch Generation

Staff notes that Potlatch's generators have been certified by the Federal Energy Regulatory Commission (FERC) as PURPA "Qualifying Facilities." As such, Avista has an obligation under PURPA to purchase power offered for sale at avoided cost rates established by the Commission. The established method for determining avoided cost rates for projects larger than 10 megawatts is an Integrated Resource Plan (IRP)-based methodology. The avoided cost methodology is described in Order No. 26576 and its accompanying Settlement Stipulation. The rate computed for Potlatch is the first under the IRP-based methodology.

A. Determination of the Contract Rate for Base Generation

Avista performed an analysis using the AURORA computer model to determine the value of Potlatch's generation. Using the same computer model, Staff reviewed the analysis and computations done by Avista, verified the input data and the assumptions and confirmed the rate offered to Potlatch. Staff believes Avista has correctly followed the methodology for computing an avoided cost rate as described in Order No. 26576. The rate for Base Generation Amounts of $42.92 per MWh is the 10-year levelized avoided cost rate from Avista's 2002 IRP. The rate represents an estimate of future market prices that fully reflects the fixed costs of new generation.

Another method used by Staff to verify the value established for Potlatch generation was to compare the purchase price to published avoided cost rates for projects 10 MW and smaller. The non-fueled published avoided cost rate for a 10-year contract length with a 2003 online date is $44.43 per MWh. These rates are based on the cost of generating energy using a gas-fired combined cycle combustion turbine (CCCT). The small difference in these two prices, Staff contends, can be justified based on the different operating characteristics of Potlatch generation and a CCCT. The 10-year levelized price approved by the Commission and paid by

Avista for Potlatch generation in the 1992 special contract was $41.50 per MWh. The annual cost for Avista to purchase Potlatch generation is only $420,000 more than it was under the old contract and will remain in effect over the entire life of the new Agreement.

Staff concludes that the contract rate for Base Generation was appropriately derived and reasonably supported and recommends approval.

B. Contract Rates for Excess and Incremental Generation Amounts

Under the Agreement, Excess Generation (i.e., amounts generated by Potlatch in excess of the Base Generation Amount) will either be purchased by Avista at 85% of the applicable Mid-Columbia (Mid-C) firm index price, with a price cap of $55 per MWh, or used by Potlatch to reduce its load requirements from Avista. The purchase of Potlatch's Excess Generation Amounts by Avista is limited to 5 aMW (43,800 MWh) each operating year. Staff believes that a purchase price equal to 85% of the Mid-C index price is reasonable. In addition, Staff contends that the rate is consistent with comparable rates paid by other utilities. The price is the same as the price paid by Idaho Power Company for the equivalent of excess energy in some of its PURPA contracts and is also equal to Idaho Power's non-firm energy rate under its electric Schedule 86.

Staff also believes it is reasonable to cap the price paid for Excess Generation amounts at $55 per MWh. A price cap of $55 will insure that Avista is not forced to pay excessive amounts, yet it will provide the Company an opportunity to purchase small amounts of energy at below market prices when supplies are limited.

Incremental Generation is energy produced by Potlatch that exceeds the Base Generation Amounts and the Excess Generation Amounts. The rates for Incremental Generation are either: a) for prescheduled generation, 85% of market price from a unit contingent sale that Avista is able to make with a third party, or b) on a real-time basis at 80% of market price for the hour. Staff believes that these rates are reasonable for Incremental Generation. As the Agreement is structured, both parties will benefit from the sale and purchase of Incremental Generation. Potlatch will be able to receive additional benefit from its extra generation during periods when market prices are high, while Avista will be able to benefit by purchasing from Potlatch at below market prices.

Staff concludes that the methodology for calculation of contract rates for Excess and Incremental Generation Amounts is reasonable and recommends approval.

Service Pricing

Staff notes that the 1992 special contract price for Avista to serve Potlatch was essentially based on electric prices in the market place. The price of all but the 25 MW of interruptible load also included floor and ceiling prices. The average cost for non-interruptible service under the old contract was approximately $42.50 per MWh in 2001.

Under the proposed Agreement, Avista will provide service to Potlatch under the terms and conditions of the Company's existing Extra Large General Service Schedule 25. This schedule requires Potlatch to pay an average base rate of $31.71 per MWh, generating approximately $27.7 million per year in base revenues. Potlatch will also be subject to the Tax Adjustment Schedule 58, the Temporary Rate Adjustment Schedule 65, the Power Cost Adjustment Schedule 66 and the Energy Efficiency Rider Adjustment Schedule 91. When the rate from non-tax Schedules 65, 66 and 91 are added to the base rate, the 2003 price paid by Potlatch for service averages $38.65 per MWh. Although Potlatch's 100 MW of load exceeds the Schedule 25 limit of approximately 25 MW, Schedule 25A which is part of Schedule 25 states:

> Customers whose demand from all such meters exceeds 25,000 KVA (25 MW) may be served under special contract wherein the rates, terms and conditions of service are specified and approved by the IPUC. If customer requires service during either the contract negotiation or resolution period, service will be supplied under this rate schedule. . . .

Potlatch, Staff notes, is by far Avista's largest single customer and electric Schedule 25 has the largest load requirement currently approved by the Commission for Avista. Absent an analysis to specifically identify Potlatch service costs, Staff contends that Schedule 25 is the most appropriate proxy to reflect Potlatch embedded cost of service. Given that current Schedule 25 rates are based on the embedded cost to serve a group of industrial customers that are much smaller than Potlatch, Staff speculates that it is likely that specific embedded costs to serve Potlatch could be lower than those used to set Schedule 25 rates. The Agreement allows either party in the context of a future proceeding to argue that the cost to serve Potlatch justifies rates that are either higher or lower than those found in Schedule 25.

Staff concludes that without a cost of service study the Agreement's proposed use of Schedule 25 as a proxy for pricing Potlatch's load is reasonable and recommends approval.

Jurisdictional Allocation

A. Background

The methodology approved by the Commission to historically allocate cost between Avista's various jurisdictions includes an allocation of all generation costs based on the jurisdictional weighting of demand and energy (67% Washington; 33% Idaho). Revenue, on the other hand, has always been directly assigned to the jurisdiction where the customer resides.

Prior to 1992, Avista paid nothing for Potlatch generation and received revenue from Potlatch based upon the net load served after Potlatch used its generation to partially offset its load. Revenues from this service arrangement remained in the Idaho jurisdiction and generation costs associated with serving the net load were allocated among the Idaho and Washington jurisdictions.

Under the 1992 special contract, Avista purchased all Potlatch generation at a pre-established price and received revenue from Potlatch based on its total load. The effect of this service arrangement under traditional jurisdictional allocation methodology was simply an increase in generation costs allocated to other jurisdictions. This is due to a traditional allocation methodology that adds generation cost to the system on the margin but allocates increased system generation costs to Idaho on the average (i.e., treating Potlatch load that was previously self-generated as having an entitlement to embedded cost resources). Allocation of all revenues on a situs basis compounded the problem. To counteract this effect, the 1992 contract approval included allocation of 60 MW of Potlatch revenues as well as purchase power costs of 60 megawatts of Potlatch generation on a jurisdictional basis. This adjustment was a compromise that balanced costs allocated to the various jurisdictions with offsetting revenues and worked fairly well because revenues from 60 megawatts of Potlatch load were fairly close to the costs of purchasing 60 megawatts of Potlatch generation.

B. Agreement – New Potlatch Allocation Methodology

Under the new Agreement, the cost of purchasing 60 megawatts of Potlatch generation is significantly higher than the revenue generated from serving 60 megawatts of Potlatch load. Consequently, the Company is proposing a different jurisdictional allocation method. Avista proposes to directly assign all revenues and costs associated with the additional 60 megawatts of Potlatch load and generation to Idaho. This allocation methodology places the net cost of buying from Potlatch and selling to Potlatch on the Idaho jurisdiction. Under the net cost of buying from Potlatch and selling to Potlatch on the Idaho jurisdiction. Under the Company's allocation proposal, all of the Company's other jurisdictions will be held harmless.

Although no other generation costs are jurisdictionally allocated in this fashion, the Company believes it is appropriate in this case because the Agreement provides the opportunity for additional benefits to Idaho customers and Idaho is the primary beneficiary of "secondary" benefits. Avista states also that it does not believe the Washington Utilities and Transportation Commission (WUTC) would accept the ratemaking consequences of the Agreement using traditional allocation methodology. Nor, the Company states, does it believe that Avista shareholders should bear the additional costs deemed unacceptable by the WUTC. The Company believes the Agreement is "an Idaho solution to an Idaho problem."

Staff notes that the Company has conditioned the appropriateness of the proposed purchase/sale rates on the Commission's approval of the Company-proposed allocation method. The fact is, Staff observes, the net cost of the Agreement increases under the proposed rates because expenses exceed revenues. For Avista to be made whole under the jurisdictional allocation previously approved for the old contract, the Company must collect a large portion of the excess costs from Washington customers. From a practical standpoint, someone must pay the difference between serving Potlatch at embedded cost and purchasing Potlatch generation at marginal cost. Staff recognizes that Potlatch is an Idaho customer providing employment and taxes in Idaho. If rates are appropriately established and if benefits accrue primarily to Idaho, Staff believes it is also reasonable to recover the costs from Idaho customers. Staff supports and recommends approval of the Company-proposed method of cost allocation.

Cost Recovery and Revenue Impact

For the purposes of this case, Staff evaluated Idaho revenue impact by comparing net revenues/costs included in base rates under the 1992 contract to revenues/costs that will be included in rates under the new Agreement. Until the new jurisdictional allocation methodology and revenues/costs of the new Agreement are included in base rates as part of a general rate case, the Company proposes to account for the changes through the Company's Idaho PCA. The comparison also reflects that Potlatch is subject to the PCA under the new Agreement but was not subject to the PCA under the old contract.

The simplest way to evaluate the impact of the new Agreement, Staff contends, is to compare the net cost of the two contracts on a system basis. The old contract had annual system expenses of $28.8 million and annual system revenues of $26.2 million for a net annual cost of $2.6 million. The new Agreement has annual system expenses of $31.25 million and annual revenues of $27.7 million for a net system cost of $3.6 million. Therefore, the new Agreement increases annual net costs by approximately $1 million on a system basis.

However, the proposed change in the jurisdictional allocation, Staff notes, shifts most of the costs to the Idaho jurisdiction. Under the jurisdictional allocation methodology approved with the old contract, the net cost allocated annually to Idaho is actually a benefit of $296,000. Under the allocation methodology proposed with the new Agreement, Idaho costs increase by $4.1 million for the term of the Agreement, from a $296,000 allocated net benefit to a $3.8 million directly assigned net cost. A $4.1 million increase in Idaho's revenue requirement represents the equivalent of a 2.3% overall rate increase. Until power purchase costs are included in base rates, the Company proposes to pass 100% of this annual expense increase through the Idaho PCA. Staff agrees with the recovery method proposed. Staff notes that Potlatch will contribute approximately $5.3 million during the current year as a Schedule 25 customer subject to the PCA. The resultant net effect of the new Agreement during the 2003 PCA period is a $1.2 million reduction in deferred costs borne by other Idaho customers.

The above analysis of revenue impact, however, is valid only under existing rates and continued service to Potlatch under Schedule 25. Staff notes that there is a possibility that the net cost of the Agreement could increase in the future if rates applied to serve Potlatch are reduced. Moreover, there will be no offsetting revenue through the PCA from Potlatch under normal water and power supply conditions to offset the effect of higher base rates. In fact, during high water conditions, Potlatch will receive some of the PCA credit that would otherwise go to other Idaho customers. However, because the rate paid to Potlatch for generation is fixed, Staff believes that it is likely that the cost differential between the cost to serve Potlatch and the cost to buy its generation will ultimately decline.

Commission Findings

The Commission has reviewed and considered the filings of record in Case No. AVU-E-03-7, including the underlying Agreement, the supporting filings of Avista and the comments and recommendations of Commission Staff. We find that the established record in this case presents an adequate basis for decision. We therefore continue to find it reasonable to process this case pursuant to Modified Procedure. Reference IDAPA 31.01.01.204.

Power Purchases (Power Deliveries to Avista)

The submitted Agreement represents that Potlatch's electric generators at its Lewiston plant are PURPA qualifying facilities. Section 210 of PURPA requires that electric utilities offer to purchase power produced by co-generation or small power producers that obtain qualifying facility (QF) status under Section 201. Under the implementing rules and regulations of the Federal Energy Regulatory Commission (FERC), the rate a QF is to receive for the sale of its power is generally referred to as the "avoided cost" rate, the incremental cost to an electric utility of electric energy or capacity or both which, but for the purchase from the QF, such utility would generate itself or purchase from another source. 18 C.F.R. § 292.101(b)(6).

The Commission finds that the $42.92/MWh levelized purchase price for the Potlatch "base generation amount" (62 aMW) is a reasonable approximation of Avista's avoided cost and was correctly calculated under the Commission approved IRP-based avoided cost methodology. Reference Order No. 26576. We further find the 10-year contract term beginning July 1, 2003 to be reasonable. Locking in the purchase rate for that term, we find, provides benefit to the Company, its Idaho customers and Potlatch.

We find the proposed market pricing method of Excess Generation amounts to be reasonable and consistent with comparable rates paid by other electric utilities. Also reasonable are the related 5 aMW operating year limit on Excess Generation and the $55 per MWh price cap. The third component of the Purchase Agreement is Incremental Generation. This generation is also market-based and is priced in a manner that we find reasonable. With market-based pricing, we find that the potential purchase of both Excess and Incremental Generation will provide benefit to the Company and its Idaho customers.

Power Sales (Power Deliveries to Potlatch)

The Agreement provides that Avista will provide electric service to Potlatch under the terms and conditions of the Company's existing extra large general service Schedule 25 tariff. Schedule 25 is a default rate for a customer as large as Potlatch. The Company's tariffs envision that a customer whose demand exceeds 25 MW will be served under a special contract. The Agreement allows either party in the context of a future proceeding to argue that Potlatch's service should be priced at rates other than Schedule 25 rates. Agreement § 5(b). Avista has informed the Commission of its intent to file a general rate case in early 2004. Absent further analysis and study Staff contends that Schedule 25 is the most appropriate proxy to reflect

Potlatch's embedded cost of service. Until the service rates for Potlatch are otherwise determined, the Commission finds that it is reasonable to serve Potlatch under Schedule 25. As a Schedule 25 tariff customer, Potlatch is subject to all the same rate adjustments applicable to other Schedule 25 customers.

Jurisdictional Allocation/Cost Recovery

The jurisdictional allocation method proposed by the Company is a departure from historical allocation. What is proposed is the allocation of 100% of Potlatch power purchase costs to Idaho. Without changing the allocation methodology, power purchase costs would be treated as generation and based on the jurisdictional weighting of demand and energy shared between Washington (67%) and Idaho (33%).

Avista and its Idaho customers have long benefited from Potlatch's self-generation capability. Prior to 1992 and from January 1, 2002 through June 30, 2003, Potlatch used its generation to reduce its load requirement while purchasing the remainder from Avista. From 1992 to 2002 Idaho received a net benefit from the Potlatch contract.

Avista contends that its proposed allocation of Potlatch power purchase costs is appropriate because Idaho realizes all the benefit of Potlatch's 100 MW of load and Schedule 25 revenue. Additional secondary benefits cited by the Company as accruing to Idaho and its citizens from Potlatch's continued operation in Lewiston are the benefits from continued employment, a bolstered tax base and economic spin-off benefits for other businesses.

As further justification for the proposed treatment of power purchase costs, the Company notes that the Washington Utilities and Transportation Commission (WUTC) takes a much different view of PURPA purchases than the Idaho Commission. Avista contends that the Agreement eliminates potential inter-jurisdictional disputes. The submitted Agreement, the Company contends, is an Idaho solution to an Idaho problem. While we appreciate the Company's perspective, we believe it is fair to recognize also that a utility operating in multiple jurisdictions has voluntarily assumed regulatory challenges and the related risk of disparate treatment.

Until such time as the purchase contract is reflected in base rates, the Company proposes to defer 100% of the power purchase costs for recovery in its Idaho PCA. We note that the generators owned by Potlatch are PURPA qualifying facilities. The purchase by Avista is obligatory and mandated by federal law and FERC regulations, i.e., 18 C.F.R. § 292.303. We have always treated purchases from PURPA QFs as non-discretionary and have authorized recovery of contract costs. The $42.92 per megawatt hour purchase price set forth in the Agreement for 62 aMW of annual base generation we find is just and reasonable and a good approximation of the Company's avoided cost. 18 C.F.R. § 292.304. The additional excess and incremental energy offered by Potlatch we find are also PURPA purchases. Potlatch is a unique customer of Avista with long and strong economic ties to Idaho. As Staff notes, from a practical standpoint, someone must pay the difference between serving Potlatch at embedded cost and purchasing Potlatch generation at marginal cost. While not choosing to speculate what the Washington Commission would do if presented with this Agreement, we find the Company's allocation proposal on the facts presented to be one of fairness and equity. As the benefits and revenue of Potlatch accrue to Idaho, so too, we find, should the related costs. Accordingly, we find it reasonable to approve the proposed allocation and method of power purchase cost recovery. In approving the requested recovery method, we authorize the booking of Avista's power purchase costs in the Company's PCA deferral account. Recovery of Potlatch power purchase costs by the Company will require a rate case or PCA filing.

Settlement of All Known Existing Disputes

Part of the mutual consideration recited in the Joint Petition is the settlement of all known existing disputes between the parties before the Idaho Commission and Idaho Courts. Joint Petition ¶ 11(b). Specifically mentioned in the Agreement are Potlatch's complaint in Idaho U.S. District Court, Case No. CV02-543-C-EJL alleging that Avista violated the terms of the 1992 Avista/Potlatch Agreement and Potlatch's complaint in Commission Case No. AVU-E-02-8 alleging that Avista had refused to purchase the co-generation output of the Lewiston plant. Agreement § 31. The Commission acknowledges that the Agreement by its terms intends to put an end to all existing litigation between the parties. We find that in addition to the cases cited, the Agreement also finally concludes Commission Case No. AVU-E-01-5, a Potlatch Petition regarding the purchase of power from Avista.

CONCLUSIONS OF LAW

The Idaho Public Utilities Commission has jurisdiction over Avista Corporation dba Avista Utilities, an electric utility, pursuant to the authority granted the Commission in Idaho Code, Title 61 and the Public Utility Regulatory Policies Act of 1978 (PURPA).

The Commission has authority under PURPA and the implementing regulations of the Federal Energy Regulatory Commission (FERC) to set avoided costs, to order electric utilities to enter into fixed term obligations for the purchase of energy from qualified facilities, and to implement FERC rules.

ORDER

In consideration of the foregoing and as more particularly described above, IT IS HEREBY ORDERED and the Commission does hereby approve the Power Purchase and Sale Agreement (Agreement) between Avista and Potlatch dated July 22, 2003.

IT IS FURTHER ORDERED and the Commission hereby authorizes the booking of all power purchase costs paid by Avista to Potlatch under the Agreement in the Company's Power Cost Adjustment (PCA) deferral account. PCA recovery of Potlatch power purchase costs is authorized until such costs are otherwise included in the Company's base rates.

THIS IS A FINAL ORDER. Any person interested in this Order may petition for reconsideration within twenty-one (21) days of the service date of this Order. Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. See *Idaho Code* § 61-626.

DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 15th day of January 2004.

PAUL KJELLANDER, PRESIDENT

MARSHA H. SMITH, COMMISSIONER

DENNIS S. HANSEN, COMMISSIONER

ATTEST:

Jean D. Jewell
Commission Secretary

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Partner

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UTILITIES COMMISSION

August 22, 2003

Ms. Jean Jewell, Secretary
Idaho Public Utilities Commission
472 West Washington Street
Boise, ID 83720-0074

Via Fedex

Re: *Potlatch Corporation v. Avista Utilities*
IPUC Docket No. AVU-E-02-08

Dear Ms. Jewell:

Enclosed please find an original plus seven (7) copies of Avista Corporation and Potlatch Corporation's Joint Petition in the above-referenced matter.

Please acknowledge receipt by date-stamping the additional copy enclosed and return to me in the self-addressed stamped envelope.

Should you have any questions regarding this filing, please do not hesitate to call me at (509) 455-6000. Thank you in advance for your assistance.

Very truly yours,

PAINE, HAMBLEN, COFFIN,
BROOKE & MILLER LLP

R. Blair Strong

R. Blair Strong

Enclosures
cc: David Meyer (w/encl.)
Conley Ward (w/encl.)
Pamela Mull (w/encl.)
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For Avista Corporation

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For Potlatch Corporation

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE JOINT PETITION OF AVISTA CORPORATION AND POTLATCH CORPORATION FOR APPROVAL OF POWER PURCHASE AND SALE AGREEMENT	CASE No. AVU-E-02-08 JOINT PETITION

Avista Corporation ("Avista") and Potlatch Corporation ("Potlatch") (Avista and Potlatch are referred to collectively as the "Parties") hereby petition the Idaho Public Utilities Commission ("Commission" or "IPUC") for an order approving the Power Purchase and Sale Agreement between Avista Corporation and Potlatch Corporation dated July 22, 2003 ("Purchase and Sale Agreement") which is attached as Exhibit 1. In support of this Petition, the Parties state as follows:

1. Avista is a corporation created and organized under the laws of the State of Washington with its principal office in Spokane, Washington. Avista is an investor-owned utility principally engaged in the business of providing electric and natural gas service in the states of Idaho and Washington, as well as natural gas service in the states of Oregon and California.

2. Potlatch is a Delaware corporation that operates a wood pulp, paperboard, tissue and wood products manufacturing facility in Lewiston, Idaho (hereinafter referred to as the "Lewiston Plant").

3. Potlatch owns and operates four generators at the Lewiston Plant that are capable of generating approximately 130 megawatts of energy. These generators are Qualifying Facilities ("QF") pursuant to the Public Utility Regulatory Policies Act of 1978, Pub. L. No. 95-617, 92 Stat. 3117 (1978) ("PURPA") and 18 C.F.R. Part 292 (2003).

4. Avista (formerly known as The Washington Water Power Company) has provided electric service to the Lewiston Plant for many years. Beginning on January 1, 1992, Avista purchased the Lewiston Plant generation output and provided electric service to the Lewiston Plant pursuant to an Electric Service and Purchase Agreement Between Potlatch Corporation and The Washington Water Power Company ("1992 Agreement"). The Commission approved the 1992 Agreement in IPUC Case No. WWP-E-91-5, Order No. 23858 on August 16, 1991.

5. The 1992 Agreement had an expiration date of December 31, 2001 and contained no provisions regarding rates, terms or conditions for service after this

expiration date. Accordingly, prior to the expiration of the 1992 Agreement, the Parties met on a number of occasions to attempt to negotiate a successor agreement.

6. The Parties were not able to reach agreement on a successor agreement and Potlatch filed a Petition with the Commission on March 23, 2001 for an order determining the terms and conditions for Potlatch's purchase of electricity from Avista, Case No. AVU-E-01-05. The Commission set Potlatch's Petition for public hearing.

7. On August 17, 2001, Potlatch and Avista filed a Joint Motion for an order vacating the hearing in Case No. AVU-E-01-05. The Parties also agreed that following the expiration of the 1992 Agreement, Avista would serve the Lewiston Plant load at Schedule 25 rates without prejudice to either Party's right to propose, or the Commission to order in future rate proceedings, that Avista's service to Potlatch should be priced at rates other than Schedule 25.

8. Since the expiration of the 1992 Agreement on December 31, 2001, Potlatch has used its Lewiston Plant generation to serve its Lewiston Plant load and Avista has served the balance of the Lewiston Plant load at Schedule 25 rates.

9. On November 25, 2002, Potlatch filed a complaint in the United States District Court for the District of Idaho, Case No. CIV02-0543-C-EJL, alleging that Avista had violated certain terms of the 1992 Agreement.

10. On December 24, 2002, Potlatch filed a Compliant with the Commission against Avista, Case No. AVU-E-02-08, alleging that Avista had refused to purchase the cogeneration output of the generation facilities at the Lewiston Plant.

11. The Parties have now reached agreement on a power purchase and sale agreement that settles the issues raised in the various pending IPUC proceedings and the

litigation in Federal Court regarding electric service at Potlatch's Lewiston Plant. The Purchase and Sale Agreement provides for both the purchase of the output of Potlatch's generation at the Lewiston Plant and for the sale of energy to serve Potlatch's load at the Lewiston Plant. In summary, the essential terms of the Agreement are as follows:

(a) The Purchase and Sale Agreement is for a ten-year term, beginning July 1, 2003 and ending June 30, 2013.

(b) The Purchase and Sale Agreement is conditioned upon approval by this Commission of: (*i*) approval of the Purchase and Sale Agreement as a settlement of all known existing disputes between the Parties, without precedential value and without prejudice to the Parties' positions on similar issues in the future; (*ii*) direct assignment of all power purchase costs paid by Avista to Potlatch under the Purchase and Sale Agreement to Avista's Idaho operations; and (*iii*) deferral and recovery of 100% of all power purchase costs paid by Avista to Potlatch under the Purchase and Sale Agreement to Avista's Idaho Power Cost Adjustment ("PCA") or otherwise recovered by Avista through base rates.

(c) Avista will be the sole purchaser of Potlatch's generation and such purchase is intended to satisfy Avista's obligations to purchase power from the Lewiston Plant pursuant to PURPA. Avista will pay Potlatch $42.92 per megawatt-hour for up to a maximum Base Generation Amount of 543,120 megawatt-hours (544,608 during a leap year) generated by Potlatch during each July 1 through June 30 period ("Operating Year") of the Agreement. This amount is equivalent to 62 average megawatts and is referred to in the Agreement as the "Base Generation Amount." Amounts generated by Potlatch in excess of the maximum Base Generation Amount each Operating Year

("Excess Generation Amounts") will either be purchased by Avista at 85% of the applicable Mid-Columbia index price, with a price-cap of $55 per megawatt-hour, or used by Potlatch to reduce its load requirements from Avista. The purchase of Potlatch's Excess Generation Amounts by Avista is limited to 43,800 megawatt-hours (5 average megawatts) each Operating Year.

Additionally, Potlatch has the capacity to generate additional amounts ("Incremental Generation Amounts") under certain circumstances. The Purchase and Sale Agreement provides for the purchase by Avista of Incremental Generation Amounts, under the terms and conditions specified in the Agreement.

(d) Avista will serve Potlatch's load requirements at Potlatch's Lewiston Plant under its Extra Large General Service Schedule 25 rates, including all applicable rate adjustments, unless the Commission issues an order in the future authorizing different billing rates.

WHEREFORE, Avista and Potlatch respectfully request that the Commission issue an order approving the Purchase and Sale Agreement, including provisions:

(1) approving the Purchase and Sale Agreement as a settlement of all known existing disputes between the Parties, including without limitation, Case No. AVU-E-01-05 and Case No. AVU-E-02-08, without precedential value and without prejudice to the Parties' positions on similar issues in the future;

(2) directly assigning all power purchase costs paid by Avista to Potlatch under the Purchase and Sale Agreement to Avista's Idaho operations; and

(3) allowing deferral and recovery of 100% of all power purchase costs paid by Avista to Potlatch under the Purchase and Sale Agreement to Avista's Idaho Power Cost Adjustment ("PCA") or otherwise recovered by Avista through base retail rates.

The Parties request that the petition be processed by modified procedure, if the Commission deems it appropriate.

DATED this 22nd day of August, 2003.

Potlatch Corporation	Paine Hamblen, Coffin, Brooke & Miller LLP
By: Pamela Mull	By: R. Blair Strong
Pamela Mull	R. Blair Strong
Associate General Counsel	Attorneys for Avista Corporation

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on the 22nd day of August, 2003, I caused to be served a true and correct copy of the foregoing by the method indicated below, and addressed to the following:

Ms. Jean Jewell, Secretary
Idaho Public Utilities Commission
472 West Washington Street
Boise, Idaho 83720-0074

_______ U.S. Mail
_______ Hand Delivery
_______ Facsimile
XXXXX Overnight Mail
_______ Electronic Mail

Conley Ward
Givens Pursley LLP
277 North 6th Street, Suite 200
P.O. Box 2720
Boise, Idaho 83701

XXXXX U.S. Mail
_______ Hand Delivery
_______ Facsimile
_______ Overnight Mail
XXXXX Electronic Mail

R. Blair Strong

R. Blair Strong

00128415

EXHIBIT 1
to

JOINT PETITION

POWER PURCHASE AND SALE AGREEMENT
BETWEEN
AVISTA CORPORATION
AND
POTLATCH CORPORATION

INDEX TO SECTIONS

POWER PURCHASE AND SALE AGREEMENT
BETWEEN
AVISTA CORPORATION
AND
POTLATCH CORPORATION

INDEX TO SECTIONS

This Power Purchase and Sale Agreement ("Agreement") is entered into as of this 22nd day of July, 2003, by and between POTLATCH CORPORATION ("Potlatch"), a corporation organized and existing under the laws of the State of Delaware, and AVISTA CORPORATION ("Avista") of Spokane, Washington, a corporation organized and existing under the laws of the State of Washington, hereinafter sometimes referred to collectively as "Parties" and individually as "Party."

WITNESSETH:

WHEREAS, Potlatch owns and operates pulp, paperboard, tissue and wood products manufacturing plants in Nez Perce County, Idaho, herein collectively referred to as the "Lewiston Plant;"

WHEREAS, Avista is presently supplying electric power to Potlatch at the Lewiston Plant;

WHEREAS, Potlatch owns and operates four thermal electric generating units located at the Lewiston Plant;

WHEREAS, there is pending before the United States District Court for the District of Idaho, Case No. CV02-543-C-EJL, a complaint by Potlatch against Avista;

WHEREAS, there is pending before the Idaho Public Utilities Commission, Case No. AVU-E-02-08, a complaint by Potlatch against Avista;

WHEREAS, the Parties desire to settle all litigation pending between them, pursuant to the terms of this Agreement;

WHEREAS, Potlatch desires to sell, and Avista desires to purchase, the Net Facility Power pursuant to the terms of this Agreement; and

WHEREAS, the Parties intend that, except for self generation by Potlatch to serve its own Load, Avista shall be the sole purchaser of Net Facility Power and the sole supplier for Potlatch Load.

NOW, THEREFORE, in consideration of the mutual covenants and agreements hereinafter set forth, the Parties agree as follows:

1. **DEFINITIONS**. In addition to words defined elsewhere in this Agreement as signified by initial capitalization, whenever used in this Agreement, exhibits and attachments hereto, the terms below shall have the following meanings:

(a) **"Bankrupt"** With respect to either Party, when such Party (i) files a petition or otherwise commences, authorizes or acquiesces in the commencement of a proceeding or cause of action under any bankruptcy, insolvency, reorganization or similar law, or has any such petition filed or commenced against it and such petition is not dismissed within sixty (60) days after it is filed, (ii) makes an assignment or any general arrangement for the benefit of creditors, (iii) otherwise becomes bankrupt or insolvent (however evidenced), (iv) has a liquidator, administrator, receiver, trustee, conservator or similar official appointed with respect to it or any substantial portion of its property or assets, or (v) is generally unable to pay its debts as they fall due.

(b) **"Base Generation Amount(s)"** That amount of Net Facility Power, expressed in megawatt-hours, less any Incremental Generation Amount, for each hour and delivered by Potlatch to Avista. The maximum Base Generation Amount for any July 1st through June 30th period (any such period referred to as the "Operating Year") shall be 543,120 megawatt-hours during a normal year or 544,608 megawatt-hours during a leap year.

(c) **"Base Period Demand"** The average kVa supplied during the 30-minute period of maximum electricity use during the portion of the billing period up to and including the point where the maximum Base Generation Amount is reached. Demand shall be calculated using a rolling 30-minute demand interval with 5-minute sub-intervals.

(d) **"Billing Period"** That period which begins at 0000 hours on the first day of any month during the term of the Agreement and ends at 2400 hours on the last day of such month.

(e) **"Effective Date"** The date this Agreement becomes effective pursuant to Section 3(a) of this Agreement.

(f) **"Excess Generation Amount(s)"** That amount of Net Facility Power, expressed in megawatt-hours, generated by the Facility, less any Incremental Generation Amount, for each hour that is in excess of the maximum Base Generation Amount of 543,120 megawatt-hours for any Operating Year during a normal year or 544,608 megawatt-hours during a leap year.

(g) **"Excess Period Demand"** The average kVa supplied during the 30-minute period of maximum electricity use during the portion of the billing period after the point where the maximum Base Generation Amount is reached. Demand shall be calculated using a rolling 30-minute demand interval with 5-minute sub-intervals.

(h) **"Facility"** The electric generating facilities, including all equipment and structures necessary to generate and supply power, more particularly described at Exhibit C (Description of the Facility).

(i) **"Facility Service Power"** Electric power used by the Facility during its operation for station service, including, but not necessarily limited to pumping, generator excitation and cooling, as further defined in Exhibit A.

(j) **"Forced Outage"** Any outage that either fully or partially curtails the electrical output of the Facility caused by mechanical or electrical equipment failure, plant related structural failure, or unscheduled maintenance required to be performed to prevent equipment failure.

(k) **"Good Industry Practice(s)"** Good industry practice as defined in the Interconnection Agreement, which definition is adopted by reference for purposes of this Agreement as though set forth in full herein.

(l) **"Governmental Authority"** Any federal, state or local government, political subdivision thereof or other governmental, regulatory, quasi-governmental, judicial, public or statutory instrumentality, authority, body, agency, department, bureau, or entity or any arbitrator with authority to bind a Party at law.

(m) **"Governmental Rule(s)"** Any law, rule, regulation, ordinance, order, code, permit, judgment, or similar form of decision of any Governmental Authority having the effect of law or regulation.

(n) **"Heavy Load Hours" ("HLH")** The hours ending 0700 through 2200 Pacific Prevailing Time, Monday through Saturday inclusive, excluding NERC holidays.

(o) **"Incremental Generation Amount(s)"** The amount of Net Facility Power expressed in megawatt-hours for each hour that is in excess of the Nominal Generation Amount.

(p) **"Index"** The daily price expressed in dollars per megawatt-hour for firm energy as published by Dow Jones for the Mid-Columbia point of delivery for the applicable Heavy Load Hours or Light Load Hours. If prices for any hour are not published for the Mid-Columbia point of delivery, Avista may extrapolate such prices using reasonable commercial judgment; *provided* that Avista shall notify Potlatch in writing of any such extrapolation and the basis thereof. In the absence of this index, a comparable publication of firm energy prices at Mid-Columbia shall be used as mutually agreed to by the Parties.

(q) **"Interconnection Agreement"** The Generation Interconnection Agreement between Potlatch and Avista.

(r) **"Light Load Hours" ("LLH")** All hours other than Heavy Load Hours.

(s) **"Load"** The hourly energy, expressed in megawatt-hours, consumed at Potlatch's Lewiston Plant excluding Facility Service Power and Losses.

(t) **"Losses"** Electric power used by the Facility during its operation to transform or transmit electric power to Points of Delivery. Losses shall be deemed to be 200 kW.

(u) **"Net Facility Power"** Electric power generated by the Facility and measured at the point of generation less Facility Service Power and less electric power used to compensate for Losses.

If any adjustment to the meter readings is required hereunder to determine the Net Facility Power actually delivered to the Points of Delivery, the electric power which the Parties agree is used by the Facility in its operation and losses to the Points of Delivery is set forth in Exhibit A.

(v) **"Nominal Generation Amount(s)"** A calculation to be performed daily and shall be the same for each hour of that day, but only used when the Parties execute a Power Purchase of Incremental Generation Amounts, to be determined as follows: The amount of electric power generated by the Facility, expressed in megawatts per hour, determined by averaging the hourly Net Facility Power generation amounts less any Power Purchases of Incremental Generation Amounts for each hour for the immediate past period counting backwards beginning two (2) days prior to the current day and consisting of thirty (30) days, not necessarily contiguous, in which the average Net Facility Power was greater than 720 megawatt-hours for each of these days (30 aMW). The Nominal Generation Amount shall be not less than fifty-five (55) megawatts per hour. The Nominal Generation Amount shall be calculated as of the date of any transaction for a Power Purchase of Incremental Generation Amounts and shall be the same amount for each hour during the term of such transaction. If the Power Purchase transaction for an Incremental Generation Amount is a prescheduled transaction, then the Nominal Generation Amount calculation will serve to set the Base Generation Amount or Excess Generation Amount for the duration of the Incremental Generation Transaction Period, and any Net Facility Power above that amount shall be deemed the Incremental Generation Amount. The "Incremental Generation Transaction Period" shall be all hours of each of the days specified for delivery of Incremental Generation Amounts that are part of a single prescheduled transaction which is also the first such transaction executed by the Parties for Incremental Generation Amount deliveries during those same days. The Incremental Generation Amount shall be set equal to zero for the purpose of calculating Base Generation Amounts (as defined in Subsection 1(b)), Excess Generation Amounts (as defined in Subsection 1(f)), and Nominal Generation Amounts during those hours in which no Incremental Generation Amount is purchased by Avista, in accordance with Section 4.

(w) **"Pacific Prevailing Time"** The Pacific Time, either standard time or daylight savings time, whichever is in effect at the relevant time.

(x) **"Points of Delivery"** The locations where the Facility is electrically interconnected with Avista's electrical system

(y) **"Power Purchase(s)"** Power transactions in which Avista purchases from Potlatch electric power generated by the Facility.

(z) **"Power Sale(s)"** Power transactions in which Potlatch purchases electric power from Avista.

(aa) **"True-up Process"** That process described in Section 3(f) for settling obligations incurred under this Agreement in the event of termination.

(bb) **"Week"** The period of time beginning at 0000 hours on any Sunday during the term of this Agreement and ending at 2400 hours on the immediately subsequent Saturday.

2. REPRESENTATIONS.

(a) Potlatch represents that it is the sole owner of the Facility, that all licenses or permits required for the operation thereof have been or will be obtained in the name of, or assigned to Potlatch, prior to the Effective Date and that the undersigned is authorized to execute this Agreement in Potlatch's behalf. Potlatch also represents that each generating unit described at Exhibit C (Description of the Facility) is a qualifying facility ("Qualifying Facility") pursuant to law and the rules of the Federal Energy Regulatory Commission.

(b) Each Party represents and warrants to the other:

(1) subject to the provisions of Subsections 3(b) and 3(c), it has all authorizations from Governmental Authority necessary for it to legally perform its obligations under this Agreement or will obtain such authorizations in a timely manner prior to the time at which any performance by it requiring such authorizations becomes due;

(2) the execution, delivery and performance of this Agreement are within its statutory and corporate powers, have been duly authorized by all necessary action and do not violate any of the terms or conditions in its governing documents, any material contract to which it is a party or by which it or any of its properties may be affected or bound, or any Governmental Rule applicable to it;

(3) this Agreement constitutes a legal, valid and binding obligation of the Party enforceable against it in accordance with its terms, and the Party has all rights such that it can and shall perform its obligations to the other Party in conformance with the terms and conditions of this Agreement, subject to bankruptcy, insolvency, reorganization and other laws affecting creditor's rights generally and general principles of equity;

(4) no Bankruptcy is pending against it, being contemplated by it, or to its knowledge threatened against it; and

(5) subject to the provisions of Subsections 3(b) and 3(c) there are no suits, proceedings, judgments, rulings or orders by or before any Governmental Authority that could reasonably be expected to have a material adverse effect on its ability to perform this Agreement.

3. <u>TERM OF AGREEMENT</u>.

(a) Subject to the provisions of this Section 3, this Agreement shall be effective at 0000 hours on July 1, 2003. Power Purchases and Sales pursuant to this Agreement shall be deemed to have commenced upon the Effective Date.

(b) Potlatch and Avista shall jointly petition the Idaho Public Utility Commission ("IPUC") for an order approving this Agreement. This Agreement is conditioned upon approval by the IPUC of the following provisions:

(1) approval of the Agreement as a settlement of all known existing disputes between the Parties, without precedential value and without prejudice to the Parties' positions on similar issues in the future;

(2) direct assignment of all Power Purchase costs paid by Avista to Potlatch under this Agreement to Avista's Idaho operations; and

(3) deferral and recovery of 100% of all Power Purchase costs paid by Avista to Potlatch under this Agreement to Avista's Idaho Power Cost Adjustment ("PCA") or otherwise recovered by Avista through base rates.

In the event that the IPUC does not approve the Agreement or approves it upon conditions that are unacceptable to Avista or Potlatch in their sole discretion, the Agreement shall terminate upon the date of such order, subject to the True-Up Process described below.

After IPUC initial approval of this Agreement, should the IPUC revise regulatory treatment of the Agreement in a manner unacceptable to Avista or Potlatch in their sole discretion, the Agreement shall terminate upon the date of such order, without being subject to the True-Up Process described below.

(c) This Agreement is conditioned upon the execution and filing with the Federal Energy Regulatory Commission ("FERC") of the Interconnection Agreement between Avista and Potlatch within sixty (60) days of the Effective Date of this Agreement. In the event that FERC does not approve the Interconnection Agreement or approves it upon conditions that are unacceptable to Avista or Potlatch in their sole discretion, this Agreement shall terminate upon the date of such order, subject to the True-Up Process described below.

(d) In the event that any third person requests rehearing of an order of the IPUC that approves the Agreement or appeals an order of the IPUC that approves this Agreement to a court of competent jurisdiction, the Agreement shall terminate upon the date of an order on rehearing or order on appeal that disapproves the Agreement or approves it upon conditions that are unacceptable to Avista or Potlatch in their sole discretion, subject to the True-Up Process described below.

(e) In the event this Agreement is not finally approved by December 31, 2003, neither Party shall have any further obligations hereunder, and this Agreement shall terminate, subject to the True-Up Process described below.

(f) **True-Up Process:** In the event that this Agreement is terminated pursuant to Subsections 3(b) through 3(e) except as otherwise provided, the Parties agree to refund amounts paid and received hereunder that exceed amounts that would have been paid and received had this Agreement not taken effect from the Effective Date to the date of termination ("Interim Period"). Such refund amounts shall be calculated as the difference between the amounts paid and received hereunder and the amounts that would have been paid and received if Potlatch had utilized its Facility to generate electricity for its own Load at the Lewiston Plant during the Interim Period and purchased its remaining electricity requirements at Schedule 25 rates. If the amount of electricity generated by the Facility exceeds the Load at the Lewiston Plant during the Interim Period, Avista shall be deemed to have purchased the amount in excess of the Load, and such purchase shall be priced at the energy rates contained in Schedule 25, calculated for each month of the Interim Period. Incremental Generation Amounts and prices paid therefor during the Interim Period shall not be subject to this True-Up Process.

(g) This Agreement shall terminate at 2400 hours on June 30, 2013.

4. <u>POWER PURCHASES (POWER DELIVERIES TO AVISTA)</u>.

(a) Potlatch shall sell and deliver and Avista shall purchase and accept delivery of Net Facility Power in accordance with the terms and conditions of this Agreement. Such purchase by Avista shall satisfy Avista's obligation to purchase power from the Facility pursuant to the Public Utility Regulatory Policies Act for the term of this Agreement. All prices for Power Purchases described in this Section 4 are all inclusive, and Avista shall not impose any charges or set-offs for transmission, losses, ancillary services or other similar costs.

(b) Avista shall pay $42.92 per megawatt-hour for the Base Generation Amount generated by the Facility each hour and delivered by Potlatch to Avista.

(c) Avista shall pay eighty-five percent (85%) of the applicable (HLH or LLH) Index price per megawatt-hour, up to a maximum price paid to Potlatch of $55 per megawatt-hour, for

Excess Generation Amounts generated by the Facility each hour and delivered by Potlatch to Avista. Potlatch may choose to not schedule and deliver Excess Generation Amounts to Avista and instead supply electric power to the Load during any Week; *provided, however*, Potlatch shall notify Avista of its election in accordance with Subsection 7(a) and such election shall be binding for the Week. In the event Potlatch does not notify Avista of its election in accordance with Subsection 7(a), Potlatch shall be deemed to have elected to supply the power to its Load for the Week. Avista shall not pay Potlatch for such Excess Generation that is not scheduled and delivered to Avista.

(d) The maximum Excess Generation Amount that Avista shall purchase for any Operating Year shall be 43,800 megawatt-hours. Excess Generation Amounts in excess of the maximum Excess Generation Amount shall be deemed used to serve Potlatch Load.

(e) Avista shall pay for Incremental Generation Amounts as set forth herein. Avista shall make price offers for Incremental Generation Amounts to Potlatch, either upon its own initiative or upon Potlatch's request, subject to Subsection 4(f) below. Prices offered by Avista shall include all Avista costs, including but not limited to, unit contingency, transmission, losses, ancillary services and other costs, but excluding third party transmission costs. Potlatch may request a price offer from Avista on a prescheduled basis for Incremental Generation Amounts consistent with Section 7. Unless the Parties otherwise agree, Avista, using reasonable commercial efforts, shall provide a price offer which shall be eighty-five percent (85%) of a unit contingent sale price that Avista is able to execute with a third party for the Incremental Generation Amount that Potlatch will make available to Avista on a prescheduled basis. If Avista is unable, after using reasonable commercial efforts to execute a unit contingent sale, or is unwilling, using reasonable commercial judgement to execute a unit contingent sale, then Avista shall not be obligated to offer a prescheduled price to Potlatch. Any Avista purchases of firm, rather than unit contingent, Incremental Generation Amounts shall be subject to separate negotiation and mutual agreement at the time of such purchases.

If the Parties are unable to mutually agree upon a prescheduled price for Incremental Generation Amounts and Potlatch desires to sell Incremental Generation Amounts to Avista, Potlatch may request a real-time price offer for the hour from Avista consistent with Section 7.

Subject to Subsection 4(f) below, if the Parties are unable to mutually agree on a real-time price for such hour, then Potlatch may elect, consistent with Section 7, to receive a price based on eighty percent (80%) of the weighted average price of Avista's real-time hourly sales and purchases for the hour in which the Parties agree that Avista will purchase Incremental Generation Amounts. If Avista has no real-time hourly purchases or sales for the hour in which Potlatch elects to sell Incremental Generation Amounts to Avista, then eighty percent (80%) of the hourly real-time market price internally recorded by Avista based on information which Avista generally discovers through its participation in the market shall be used as the price for the Incremental Generation Amount for such hour.

(f) Avista shall use the same degree of care and effort to purchase and, if necessary, to resell Incremental Generation Amounts as it uses in selling electric power from Avista owned generating resources. Notwithstanding anything in this Agreement, Avista reserves the right to refuse to purchase Incremental Generation Amounts due to commercially reasonable internal policy limitations prohibiting purchases for resale or Governmental Rules prohibiting purchases for resale. Avista shall make reasonable efforts to notify Potlatch in advance of such internal policy limitations or Governmental Rules.

(g) With regard to a prescheduled purchase of an Incremental Generation Amount, at the time of execution of the transaction, Avista shall provide Potlatch with a facsimile copy of the transaction confirmation that shall include the mutually agreed upon price and estimated Incremental Generation Amount as provided by Potlatch. With regard to a real-time purchase of an Incremental Generation Amount, at the time of execution of the transaction, Avista shall provide Potlatch with a voice confirmation of either the price or Potlatch's election to take the calculated price, in accordance with Subsection 4(e). Potlatch shall provide a voice confirmation of the estimated Incremental Generation Amount. Potlatch may call Avista's real-time scheduler in the hour following the hour of delivery of the Incremental Generation Amount and Avista shall provide the real-time market price internally recorded in accordance with Subsection 4(e) for Potlatch's information purposes only.

(h) Multiple Incremental Generation Amount transactions within a single hour: Should the Parties enter into more than one transaction for delivery in any hour of Incremental Generation Amounts, then the actual Incremental Generation Amounts produced by Potlatch's Facility will be first committed to the transaction entered into on the earliest date and time and the remaining actual Incremental Generation Amounts will be committed to the remaining transactions in the order in which the Parties entered into those transactions.

5. POWER SALES (POWER DELIVERIES TO POTLATCH).

(a) Avista shall sell and deliver and Potlatch shall purchase and accept delivery of electric power and energy required for Potlatch's Load at the Lewiston Plant for the duration of the Agreement in accordance with the terms and conditions of this Agreement, Avista's Rules and Regulations in effect with the IPUC, applicable tariff schedules and orders of the IPUC in effect at the time electric power is delivered hereunder, as they may be changed from time to time, and any other requirements imposed by law, provided:

(1) Avista shall not be obligated to provide to Potlatch Facility Service Power or Losses; and

(2) Any demand charge assessed to Potlatch for periods in which Power Purchases are made shall be based on either:

(i) The coincident hourly sum of (1) Net Facility Power produced by the Facility (expressed in kilowatts) and (2) electric power (expressed in kilowatts) that flows from Avista's electric system to the Potlatch Load added vectorily to only the reactive power ("kVARs") that flows from Avista's electric system to the Potlatch Load during periods when Avista purchases from Potlatch either Base Generation Amounts or Excess Generation Amounts, or;

(ii) The coincident hourly sum of (1) Incremental Generation Amounts produced by the Facility (expressed in kilowatts) and (2) electric power (expressed in kilowatts) that flows from Avista's electric system to the Potlatch Load added vectorily to only the reactive power ("kVARs") that flows from Avista's electric system to the Potlatch Load during periods when Potlatch elects to use Excess Generation Amounts to serve its Load.

Reactive power produced by the Facility as described in either of the cases under Subsection 5(a)(2)(i) or 5(a)(2)(ii) above shall not be included in the demand calculation.

(3) Any demand charge assessed to Potlatch for periods in which no Power Purchases are made shall be based only on kilowatts that flow from Avista's electric system to the Potlatch Load added vectorily to only the reactive power that flows from Avista's electric system to the Potlatch Load.

(b) Avista shall bill for all electric power delivered by Avista for Potlatch's Load at the rates set forth in Avista's Extra Large General Service Schedule 25, including all adjustments thereto, unless and until such time as the IPUC issues an order authorizing Avista to bill at a different rate. Nothing shall prejudice any Party's right to propose, or the Commission to order, in future proceedings that Potlatch's service should be priced at rates other than Schedule 25 rates. This Agreement shall not be construed as restricting the right of either Party to petition the IPUC to establish, disestablish, amend or alter Avista's Rules and Regulations in effect with the IPUC, applicable tariff schedules and orders of the IPUC, including but not limited to Schedule 25.

6. <u>OPERATION OF FACILITY</u>.

(a) Potlatch shall construct, operate and maintain the Facility and associated electrical equipment in compliance with Qualifying Facility status and in accordance with applicable laws and regulations and in accordance with Good Industry Practice. Potlatch shall construct, operate and maintain the Facility and other equipment associated with the Lewiston Plant at its own risk and expense. Avista shall construct, operate and maintain its interconnection facilities, that portion of its system that is interconnected to the Facility, and all equipment needed to receive and transmit electric power in accordance with applicable laws and regulations and in accordance with the Interconnection Agreement and Good Industry Practice.

(b) Interconnection of electrical systems under this Agreement shall be governed by the Interconnection Agreement. Nothing herein is intended to amend or alter the Interconnection Agreement as it may be amended or superceded. In the event that the Interconnection Agreement is superceded or amended as a consequence of a lawful order of the Federal Energy Regulatory Commission, or other agency or court having jurisdiction thereof, the Parties agree to negotiate in good faith such amendments to this Agreement as are necessary to preserve the intent of this Agreement. Subject to Governmental Rules, in the event of a conflict between the terms of this Agreement and the Interconnection Agreement, the terms of this Agreement shall take precedence.

(c) Exhibit B (Communications), attached hereto, shall govern communications between Potlatch and Avista for purposes of this Agreement.

(d) Potlatch shall provide Avista as much notice as is reasonably practicable under the circumstances in the event of any planned increase to or reduction in its Load of more than 10,000 kilowatts. Potlatch shall also provide as much notice as is reasonably practicable under the circumstances of any planned outages of the Facility and any planned increase or reduction of generation from the Facility of more than 10,000 kilowatts. The notices shall specify the amount and the expected duration of such outages, increases and reductions.

(e) Potlatch shall use its best efforts to maintain its Load on Avista's electric system (at the Points of Delivery) at a power factor of 95% or higher throughout the term of this Agreement. Avista shall not be liable for any loss or damage incurred by Potlatch resulting solely from Potlatch's failure to maintain a power factor of 95% or higher.

(f) The Parties acknowledge that Avista's electric power system and delivery facilities, under certain circumstances, may constrain power deliveries to Potlatch's Lewiston Plant. Potlatch shall notify Avista of any intention to increase its energy and demand requirements at the Lewiston Plant beyond the capacity of Avista's facilities. The Parties shall negotiate in good faith the terms and conditions of a mutually acceptable separate agreement to install additional facilities required to accommodate additional energy and demand requirements, subject to approval by the IPUC and consistent with FERC rules and regulations.

(g) Potlatch agrees to adhere to IEEE 519 guidelines for power quality.

7. SCHEDULING.

(a) General Scheduling: Potlatch shall submit to Avista pre-schedulers its estimated hourly schedules for Base Generation Amounts, Excess Generation Amounts, and Load for each Week, and shall make commercially reasonable efforts to deliver electric power as scheduled. Potlatch shall also indicate, pursuant to Subsection 4(c), whether it will sell Excess Generation Amounts to Avista or elects to instead supply Excess Generation Amounts to its Load for the Week. Potlatch shall insure that such submission is received by Avista no later than 1700 hours Pacific Prevailing Time of the second-to-the-last business day observed by both Parties of the Week preceding the Week to be pre-scheduled by facsimile or other similar written form. Potlatch shall also call Avista's real-time scheduler as soon as practical if there are material changes to expected generation amounts or Load.

(b) Day-Ahead Incremental Generation Amount Scheduling Estimates: Potlatch shall submit to Avista's pre-schedulers its best estimates of hourly Incremental Generation Amounts by 0600 hours Pacific Prevailing Time on the business day observed by both Parties immediately preceding the day or days on which electric power is to be delivered, unless otherwise mutually agreed by the Parties.

(c) Real-Time Incremental Generation Amount Schedules: Potlatch shall contact Avista real-time schedulers no earlier than two hours and not later than one hour prior to the hour in which power is to be delivered to communicate its best estimate of hourly Incremental Generation Amounts and any material change in expected electric power deliveries or changes in Load.

8. BILLING AND PAYMENTS.

(a) So long as there are Power Sales made and/or payments due hereunder, Avista shall prepare monthly an itemized billing of the payment due, including the amounts of Power Purchases, Power Sales, the appropriate rates, and any adjustments to the payment consistent with the provisions herein. Payments for amounts billed shall be received by the Party to be paid on the due date, which shall be either the 20th day of the month following the Billing Period or ten (10) days after receipt of the bill, whichever is later ("Due Date"). Payment shall be made at the location designated by the Party to which payment is due. If the Due Date falls on a non-business day of either Party, then the payment shall be due on the next following business day.

(b) Subject to Subsection (c) below, any payments by Avista to Potlatch or by Potlatch to Avista, if not paid in full within the limitations set forth in Subsection (a), shall be late. In addition to the other remedies for such an Event of Default pursuant to this Agreement, the late-paying Party shall be assessed a charge for late payment equal to the lesser of one percent (1%) per whole or partial month, or the maximum rate allowed by the laws of the State of Idaho per whole or partial month multiplied by the overdue amount. Each Party shall have the right to offset any amounts due it against any present payments owed to the other Party.

(c) If a Party in good faith disputes a bill prepared by the other Party, the disputing Party may pay or withhold the amount in dispute. If a disputing Party elects to pay or withhold the amount in dispute, it shall provide a written notice to the other Party at the same time that payment would be normally due, which notice shall specifically set forth the basis of the dispute. The Parties agree as soon as practicable to negotiate the dispute and failing negotiation, to otherwise resolve the dispute in the most expeditious manner practicable. If the disputing Party elects to withhold the disputed amount, and if the billing dispute is resolved in favor of the Party that prepared the bill, the disputing Party shall pay to the billing Party the amount withheld with interest accrued at the rate set forth in Subsection (b) above, multiplied by the withheld amount, prorated by months and partial months from the original date that the amount should have been paid to the actual date of payment. If the disputing Party elects to pay the disputed amount, and the billing dispute is resolved in favor of the disputing Party, the Party that prepared the bill shall refund the disputed amount to the disputing Party, with interest accrued at the rate set forth in Subsection (b) above multiplied by the disputed amount, prorated by months and partial months from the date that the amount was paid to the date of refund.

(d) Potlatch may verify information used in preparing invoices by examining Avista documents in its Spokane office for a period up to ninety (90) days after the billing date. All information, records and reports related to Power Purchases or Power Sales under the terms of this Agreement, and the calculation of prices therefor, will be open to inspection by Potlatch upon reasonable notice and provided that Potlatch shall keep all such information confidential and use it only for purposes of this Agreement, and further provided that in any enforcement proceedings, Potlatch shall avail itself of procedures to protect the confidentiality of such information under the applicable Governmental Rules.

(e) Avista shall prorate amounts billed to Potlatch for demand and other charges, in accordance with the provisions of this Section, during the initial month of Power Purchases and Power Sales under this Agreement if such purchases and sales commence on any day other than the first day of the month, and during any Billing Period in which Potlatch elects to use Excess Generation Amounts to serve the Load as permitted in Section 4(c). The Power Sales demand quantities, expressed in kilovolt-amperes ("kVa") shall be prorated for the purposes of calculating the demand charge for the applicable Billing Periods. For the applicable Billing Periods, the prorated demand quantity components shall be calculated as follows: (1) Base Period Demand, expressed in kVa, during that portion of the Billing Period in which Avista made Power Purchases of Base Generation Amounts from Potlatch multiplied by the number of days (rounded to the nearest whole day) in the Billing Period in which Avista made Power Purchases of Base Generation Amounts from Potlatch and then divided by the total number of days in the Billing Period; (2) Excess Period Demand, expressed in kVa, during that portion of the billing period in which Avista made no Power Purchases other than Incremental Generation Amounts from Potlatch multiplied by the number of days (rounded to the nearest whole day) in the Billing Period in which Avista made no Power Purchases other than Incremental Generation Amounts from Potlatch and then divided by the total number of days in the Billing Period; (3) Excess Period Demand, expressed in kVa, during that portion of the Billing Period in which Avista purchased Excess Generation Amounts from Potlatch multiplied by the number of days (rounded to the nearest whole day) in the Billing Period in which Avista made Power Purchases of Excess Generation Amounts from Potlatch and then divided by the total number of days in the Billing Period. Prorated total demand quantity, expressed in kVa, is calculated from the arithmetic sum of (1), (2) and (3) above. The resultant total demand quantity shall be used for calculation of the demand charge.

(f) Adjustments shall be made in billings for errors in a meter reading or in a billing discovered within thirty-six (36) months of the error.

9. METERING.

(a) Metering shall be governed by the provisions of Exhibit A.

(b) Avista shall be responsible for any meter readings required by this Agreement.

10. TERMINATION OF AGREEMENT.

Subject to the Force Majeure provision of this Agreement, the Agreement may be terminated at Avista's sole option, if any of the following conditions occur.

(a) Potlatch abandons the Facility or otherwise renders the Facility incapable of generating electric power; or

(b) There have been no electric power deliveries to Avista from the Facility for a period of twelve (12) consecutive months; or

(c) The electric power deliveries from the Facility to Avista fail to exceed 175,200 megawatt-hours during any rolling period of twenty-four (24) consecutive months, which rolling period commences any time after the first twelve (12) consecutive months following the Effective Date.

11. FORCED OUTAGE AND FORCE MAJEURE.

(a) Neither Party shall be liable to the other Party for, or be considered to be in breach of or default under this Agreement, on account of any delay in performance due to any of the following events, which event or circumstance was not anticipated as of the Effective Date ("Force Majeure"):

(1) Any cause or condition beyond such Party's reasonable control that such Party is unable to overcome by the exercise of reasonable diligence, including but not limited to: fire, flood, earthquake, volcanic activity, wind, drought and other acts of the elements; court order and act of civil, military or governmental authority; strike, lockout and other labor dispute; riot, insurrection, terrorism, sabotage or war; Governmental Rules; Forced Outage; breakdown of or damage to facilities or equipment; electrical disturbance originating in or transmitted through such Party's electric system or any electric system with which such Party's system is interconnected; any interruption of transmission service required for the performance of this Agreement that is excused by reason of force majeure or uncontrollable forces under a Party's contract with a transmission service provider; and, any act or omission of any person or entity other than such Party, and Party's contractors or suppliers of any tier or anyone acting on behalf of such Party; or

(2) Any action taken by such Party which is, in the sole judgment of such Party, necessary or prudent to protect the operation, performance, integrity, reliability or stability of such Party's electric system or any electric system with which such Party's electric system is interconnected, whether such actions occur automatically or manually.

(b) In the event of any Force Majeure occurrence, the time for performance thereby delayed shall be extended by a period of time reasonably necessary to compensate for such delay. Nothing contained in this paragraph shall require any Party to settle any strike, lockout or other labor dispute. In the event of a Force Majeure occurrence, which will affect performance under this Agreement, the nonperforming Party shall provide the other Party written notice as soon as practicable after the occurrence of the Force Majeure event. Such notice shall include the particulars of the occurrence, assurances that suspension of performance is of no greater scope and of no longer duration than is required by the Force Majeure and that best efforts are being used to remedy its inability to perform. The nonperforming Party shall remedy the Force Majeure occurrence with all reasonable dispatch. The performing Party shall not be required to perform or resume performance of its obligations to the nonperforming Party corresponding to the obligations of the performing Party excused by the Force Majeure occurrence.

(c) Force Majeure does not include changes in the ownership, occupancy, or operation of the Facility or Avista if such changes occur because of normal business occurrences which include but are not limited to: changes in business economic cycles; recessions; bankruptcies; tax law changes; sales of businesses; closure of businesses; changes in production levels; and, changes in system operations.

(d) Force Majeure does not excuse any Party from making payments of money due under this Agreement for power purchased prior to the Force Majeure event.

12. INDEMNITY.

(a) **Potlatch's Duty to Indemnify**. Potlatch shall indemnify, hold harmless and defend Avista, and its officers, directors, employees, affiliates, managers, members, trustees, shareholders, agents, contractors, subcontractors, affiliates' employees, invitees and successors, from and against any and all third party claims, demands, suits, obligations, payments, liabilities, costs, losses, judgments, damages and expenses (including the reasonable costs and expenses of any and all actions, suits, proceedings, assessments, judgments, settlements, and compromises relating thereto, reasonable attorneys' and expert fees and reasonable disbursements in connection therewith) for damage to property, injury to any person or entity, or death of any individual, including Avista's employees and affiliates' employees, Potlatch's employees, or any other third parties, to the extent caused wholly or in part by any act or omission, negligent or otherwise, by Potlatch or its officers, directors, employees, agents, contractors, subcontractors and invitees arising out of or connected with Potlatch's performance or breach of this Agreement, or the exercise by Potlatch of its rights hereunder; *provided, however*, that the provisions of this Section shall not apply if any such injury, death or damage is held to have been caused by the sole negligence or intentional wrongdoing of Avista, its agents or employees. The foregoing indemnification obligation shall not be limited in any way by workers' compensation laws or by any limitation on the amount or type of damages, compensation or benefits payable by Potlatch under applicable workers' compensation laws.

(b) Avista's Duty to Indemnify. Avista shall indemnify, hold harmless and defend Potlatch, and its officers, directors, employees, affiliates, managers, members, trustees, shareholders, agents, contractors, subcontractors, invitees and successors, from and against any and all third party claims, demands, suits, obligations, payments, liabilities, costs, losses, judgments, damages and expenses (including the reasonable costs and expenses of any and all actions, suits, proceedings, assessments, judgments, settlements, and compromises relating thereto, reasonable attorneys' and expert fees and reasonable disbursements in connection therewith) for damage to property, injury to any entity or person, or death of any individual, including Potlatch's employees and affiliates' employees, Avista's employees, or any other third parties, to the extent caused wholly or in part by any act or omission, negligent or otherwise, by Avista or its officers, directors, employees, agents, contractors, subcontractors and invitees arising out of or connected with Avista's performance or breach of this Agreement, or the exercise by Avista of its rights hereunder; *provided, however*, that the provisions of this Section shall not apply if any such injury, death or damage is held to have been caused by the sole negligence or intentional wrongdoing of Potlatch, its agents or employees. The foregoing indemnification obligation shall not be limited in any way by workers' compensation laws or by any limitation on the amount or type of damages, compensation or benefits payable by Avista under applicable workers' compensation laws.

(c) Notice. A Party seeking indemnification under this Agreement ("First Party") shall give the other Party ("Second Party") notice of the claim or action giving rise to a right of indemnification as soon as practicable, but in any event on or before the thirtieth (30^{th}) day after the First Party's actual knowledge of such claim or action. The notice shall describe the claim or action in reasonable detail, and shall indicate the amount (estimated if necessary) of the claim or action. Any failure of the First Party to provide the notice required by this Section shall not affect the First Party's rights to indemnification except to the extent the Second Party is actually and materially prejudiced as a result of such failure. Neither Party may settle or compromise any claim for which indemnification is sought under this Agreement without the prior consent of the other Party; *provided, however*, said consent shall not be unreasonably withheld or delayed. Each Party's indemnification obligation shall survive expiration, cancellation or early termination of this Agreement.

(d) **Acknowledgment to Negotiation**. **POTLATCH AND AVISTA SPECIFICALLY WARRANT THAT THE TERMS AND CONDITIONS OF THE FOREGOING INDEMNITY PROVISIONS ARE THE SUBJECT OF MUTUAL NEGOTIATION BY THE PARTIES, AND ARE SPECIFICALLY AND EXPRESSLY AGREED TO IN CONSIDERATION OF THE MUTUAL BENEFITS DERIVED UNDER THE TERMS OF THE AGREEMENT.**

13. LIMITATION OF LIABILITY.

(a) **Limitation of Liability**. With respect to claims by and between the Parties under this Agreement, the measure of damages at law or in equity in any action or proceeding shall be limited to direct actual damages only. Such direct actual damages shall be the sole and exclusive remedy and all other remedies or damages at law or in equity are waived and neither Party shall be liable in statute, contract, in tort (including negligence), strict liability, warranty or under any other legal theory or otherwise to the other Party, its agents, representatives, and/or assigns, for any special, incidental, punitive, exemplary or consequential loss or damage whatsoever, including, but not limited to, loss of profits or revenue for work not performed, for loss of use of or under-utilization of the other Party's facilities, loss of use of revenues, attorneys' fees, litigation costs, or loss of anticipated profits, resulting from either Party's performance or non-performance of an obligation imposed on it by this Agreement, without regard to the cause or causes related thereto, including the negligence of any Party. The Parties expressly acknowledge and agree that this limitation shall not apply to any claims for indemnification under Section 12 of this Agreement. The provisions of this Section shall survive the termination or expiration of this Agreement.

(b) **Limitation of Liability for WIS Parties**. Notwithstanding the provisions of Subsection (a) above, if both Avista and Potlatch are parties to the Western Interconnected Systems Limitation of Liability ("WIS") Agreement, then the WIS Agreement shall control their liabilities with respect to damages to the Facility, the interconnection facilities, or Avista's electric system.

14. INSURANCE.

(a) **General Liability**. The Parties agree to maintain, at their own cost and expense, general liability, workers' compensation, and other forms of insurance relating to their operations for the life of this Agreement in the manner, and amounts, at a minimum, as set forth below.

(1) Workers' compensation insurance in accordance with all applicable state and federal law, including Employer's Liability Insurance in the amount of $1,000,000 per occurrence;

(2) Commercial General Liability Insurance, including Contractual Liability Coverage for liabilities assumed under this Agreement, and Personal Injury Coverage in the minimum amount of $5,000,000 per occurrence for bodily injury and property damage. Potlatch's policy shall include Avista as an additional insured.

(3) Where a Party has more than $100 million in assets it may, at its option, self-insure all or part of the insurance required in this Section 14; *provided, however*, the self-insuring Party agrees that all other provisions of this Section 14, including, but not limited to, waiver of subrogation, waiver of rights of recourse, and additional insured status, which provide or are intended to provide protection for the other Party and its affiliated and associated companies under this Agreement, shall remain enforceable. A Party's election to self-insure shall not impair, limit, or in any manner result in a reduction of rights and/or benefits otherwise available to the other Party and its affiliated and associated companies through formal insurance policies and endorsements as specified in the above parts of this Section 14. The self-insuring Party agrees that all amounts of self-insurance, retentions and/or deductibles are the responsibility of and shall be borne by the self-insuring Party.

(b) <u>Certificates</u>. Within fifteen (15) days of the Effective Date, and each anniversary of the Effective Date, during the term of this Agreement, (including any extensions), each Party shall provide to the other Party, properly executed and current certificates of insurance with respect to all insurance policies required to be maintained by such Party under this Agreement. Certificates of insurance shall provide the following information:

(1) Name of insurance company, policy number and expiration date;

(2) The coverage required and the limits on each, including the amount of deductibles or self-insured retentions, which shall be for the account of the Party maintaining such policy;

(3) A statement indicating that the other Party shall receive at least thirty (30) days prior written notice of cancellation or expiration of a policy, or reduction of liability limits with respect to a policy; and

(4) A statement identifying and indicating that additional insureds have been named as required by this Agreement.

(c) <u>Policy Request</u>. At a Party's request, in addition to the foregoing certifications, the other Party shall deliver to the first Party a copy of applicable sections of each insurance policy.

(d) <u>Inspection</u>. Each Party shall have the right to inspect the original policies of insurance applicable to this Agreement at the other Party's place of business during regular business hours.

(e) <u>"Claims Made" Insurance</u>. If any insurance is written on a "claims made" basis, the respective Party shall maintain the coverage for a minimum of seven years after the termination of this Agreement.

(f) <u>Waiver of Subrogation</u>. To the extent permitted by the insurer and commercially reasonable, each Party shall obtain waivers of subrogation in favor of the other Party from any insurer providing coverage that is required to be maintained under this Section 14. A Party shall not be required to obtain a waiver of subrogation if the other Party is not able to obtain a waiver of subrogation from its insurance carrier.

15. ASSIGNMENT.

Neither Party shall voluntarily assign its rights or delegate its duties under this Agreement, or any part of such rights or duties without the written consent of the other Party. Such consent shall not unreasonably be withheld. Further, no assignment by either Party shall relieve or release it to the extent of any of its obligations hereunder. Subject to the foregoing restrictions on assignments, this Agreement shall be fully binding upon, inure to the benefit of and be enforceable by the Parties and their respective successors, heirs and assigns.

16. NO UNSPECIFIED THIRD PARTY BENEFICIARIES.

Except as specifically provided in this Agreement, there are no third party beneficiaries of this Agreement. Nothing contained in this Agreement is intended to confer any right or interest on anyone other than the Parties, and their respective successors, heirs and assigns permitted under Section 15.

17. NO TRANSMISSION RIGHTS.

Nothing in this Agreement shall be construed as granting Potlatch any right of access, or any other rights, to Avista's transmission system.

18. BENEFITS FOR RENEWABLE FUELS.

Nothing in this Agreement shall affect Potlatch's rights to benefits attributable to Potlatch's use of renewable fuels for generation. The Parties further agree to negotiate in good faith should it be necessary at a later date, to develop a separate agreement in order to provide Potlatch with those benefits.

19. DEFAULT.

(a) An "Event of Default" shall mean, with respect to a Party (a "Defaulting Party"), the occurrence of any of the following:

(1) the failure to make, when due, any payment required pursuant to this Agreement if such failure is not remedied within three (3) business days after delivery of written notice;

(2) any representation or warranty made by such Party herein is false or misleading in any material respects when made or when deemed made or repeated;

(3) the failure to perform any material covenant or obligation set forth in this Agreement (except to the extent constituting a separate Event of Default) if such failure is not remedied within thirty (30) business days after delivery of written notice;

(4) such Party becomes Bankrupt; or

(5) such Party consolidates or amalgamates with, or merges with or into, or transfers all or substantially all of its assets to, another entity and, at the time of such consolidation, amalgamation, merger or transfer, the resulting, surviving or transferee entity fails to assume all the obligations of such Party under this Agreement to which it or its predecessor was a party by operation of law or pursuant to an agreement reasonably satisfactory to the other Party.

(b) In the Event of Default, the following shall apply:

(1) The non-defaulting Party shall give written notice to the Defaulting Party of the Event of Default in accordance with this Agreement.

(2) Except for an Event of Default that arises from failure to make money payments or from a Party becoming bankrupt, if, after 30 days following receipt of such notice, the Defaulting Party has not taken the steps necessary to cure the event of default, the non-defaulting Party may, at its option, terminate this Agreement; *provided, however*, that except for the failure to pay sums which are due and payable, if the defaulting Party, within such 30-day period, commences and thereafter proceeds with all due diligence to cure such default, such 30-day period shall be extended up to six (6) months after written notice to the defaulting Party, as may be necessary to cure the event of default with all due diligence. For an Event of Default that arises from the failure to make money payments, the non-defaulting Party may, at its option, terminate this Agreement if the Defaulting Party shall have failed to cure the failure to pay within

three (3) business days following receipt of notice of such failure. For an Event of Default that arises from a Party becoming bankrupt, the non-defaulting Party may, at its option, immediately terminate this Agreement upon notice to the Defaulting Party.

(3) Upon the Event of Default and an expiration of any period to cure granted herein, the non-defaulting Party may, but has no obligation, to terminate this Agreement effective upon notice to the Defaulting Party and may exercise all other rights and remedies available to the non-defaulting Party under applicable law. Whether or not the non-defaulting Party elects to terminate this Agreement, it may, in addition to other remedies provided for herein, pursue such remedies as are available at law or in equity including suspension of its performance so long as the Event of Default is continuing and has not been cured.

(c) Any right or remedy afforded to either Party under any provision of this Agreement on account of the breach or default by the other Party is in addition to, and not in lieu of, all other rights or remedies afforded to such Party under any other provisions of this Agreement, by law or otherwise on account of the breach or default.

20. RELEASE BY AVISTA.

Avista releases Potlatch from any and all claims, losses, harm, liabilities, damages, costs and expenses to the extent resulting from any disconnection, interruption, suspension or curtailment by Potlatch pursuant to terms of this Agreement.

21. RELEASE BY POTLATCH.

Potlatch releases Avista from any and all claims, losses, harm, liabilities, damages, costs and expenses to the extent resulting from any disconnection, interruption, suspension or curtailment by Avista pursuant to terms of this Agreement.

22. GOVERNMENTAL AUTHORITY.

This Agreement is subject to the Governmental Rules now or hereafter in effect, of all Governmental Authorities having jurisdiction over the Facility, this Agreement, the Parties or either of them. All Governmental Rules that are required to be incorporated in agreements of this character are by this reference incorporated in this Agreement.

23. SEVERAL OBLIGATIONS.

Except where specifically stated in this Agreement to be otherwise, the duties, obligations and liabilities of the Parties are intended to be several not joint or collective. This Agreement shall not be interpreted or construed to create an association, joint venture or partnership between the Parties or to impose any partnership obligations or liability upon either Party. Each Party shall be individually and severally liable for its own obligations under this Agreement. Further, neither Party shall have any rights, power or authority to enter into any agreement or undertaking for or on behalf of, to act as or to be an agent or representative of, or to otherwise bind the other Party.

24. IMPLEMENTATION.

Each Party shall take such action (including, but not limited to, the execution, acknowledgement and delivery of documents) as may reasonably be requested by the other Party for the implementation or continuing performance of this Agreement.

25. NON-WAIVER.

The failure of either Party to insist upon or enforce strict performance by the other Party of any provision of this Agreement or to exercise any right under this Agreement shall not be construed as a waiver or relinquishment to any extent of such Party's right to assert or rely upon any such provision or right in that or any other instance; rather, the same shall be and remain in full force and effect.

26. ENTIRE AGREEMENT AND AMENDMENT.

This Agreement together with its exhibits constitutes the entire agreement of the Parties hereto and supersedes and replaces any prior agreements or understandings between said Parties, entered into for the same or similar purposes, with the exception the Interconnection Agreement. No change, amendment or modification of any provision of this Agreement shall be valid unless set forth in a written amendment to this Agreement signed by both Parties.

27. VENUE, ATTORNEYS FEES AND CHOICE OF LAW.

Venue of any action filed to enforce or interpret the provisions of this Agreement shall be exclusively in the United States District Court for the District of Idaho or the District Court of the State of Idaho encompassing Nez Perce County and the Parties irrevocably submit to the jurisdiction of any such court. In the event of litigation to enforce the provisions of this Agreement, the prevailing Party shall be entitled to reasonable costs and attorney's fees in addition to any other relief allowed. Notwithstanding conflict of law rules, the laws of the State of Idaho shall apply to disputes arising under this Agreement.

28. COMPLIANCE WITH LAWS.

Both Parties shall comply with all applicable laws and regulations of Governmental Authorities having jurisdiction over the Facility and the operations of the Parties.

29. CONFIDENTIALITY.

(a) **Definition**. "Confidential Information" shall mean any confidential, proprietary or trade secret information or a plan, specification, pattern, procedure, design, device, list concept, policy or compilation relating to the present or planned business of a Party, which is designated in good faith as confidential by the Party supplying the information, whether conveyed orally, electronically, in writing, through inspection or otherwise, except that the real-time in-plant data, shall be considered Confidential Information without the need for designation.

(b) **General Obligations**.

(1) Each Party shall hold in confidence any and all Confidential Information unless: (*i*) compelled to disclose such information by Governmental Rules or as otherwise provided for in this Agreement; or (*ii*) to meet obligations imposed by Governmental Authority or by membership in NERC or WECC (including other transmission providers). Information required to be disclosed under (*i*) or (*ii*) above, does not, by itself, cause any information provided by Potlatch to Avista to lose its confidentiality. To the extent it is necessary for either Party to release or disclose such information to a third party in order to perform that Party's obligations herein, such Party shall advise said third party of the confidentiality provisions of this Agreement and use its best efforts to require said third party to agree in writing to comply with such provisions.

(2) During the term of this Agreement, and for a period of three (3) years after the expiration or termination of this Agreement, except as otherwise provided in this Section 29, each Party shall hold in confidence and shall not disclose to any person Confidential Information.

(3) Each Party shall use at least the same standard of care to protect Confidential Information it receives as it uses to protect its own Confidential Information from unauthorized disclosure, publication or dissemination.

(c) **Excluded Information**. Confidential Information shall not include information that the receiving Party can demonstrate: (*i*) is generally available to the public other than as a result of disclosure by the receiving Party; (*ii*) was in the lawful possession of the receiving Party on a non-confidential basis prior to receiving it from the disclosing Party; (*iii*) was supplied to the receiving Party without restriction by a third party, who, to the knowledge of the receiving party, after due inquiry was under no obligation to the disclosing party to keep such information confidential; (*iv*) was independently developed by the receiving party without reference to Confidential Information of the disclosing party; (*v*) is, or becomes, publicly known, through no wrongful act or omission of the receiving Party or Breach of this Agreement; or (*vi*) is required, in accordance with Subsection 29(d) of this Agreement, to be disclosed by any Governmental Authority or is otherwise required to be disclosed by law or subpoena, or is necessary in any legal proceeding establishing rights and obligations under this Agreement. Information designated as Confidential Information will no longer be deemed confidential if the Party that designated the information as confidential notifies the other Party that it no longer is confidential.

(d) **Subpoena**. If a Governmental Authority or entity with the right, power, and apparent authority to do so requests or requires either Party, by subpoena, oral deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Party with prompt notice of such request(s) or requirement(s) so that the other Party may seek an appropriate protective order or waive compliance with the terms of this Agreement. The notifying Party shall have no obligation to oppose or object to any attempt to obtain such production except to the extent requested to do so by the disclosing Party and at the disclosing Party's expense. If either Party desires to object or oppose such production, it must do so at its own expense. The disclosing Party may request a protective order to prevent any Confidential Information from being made public. Notwithstanding the absence of a protective order or waiver, the Party may disclose such Confidential Information which, in the opinion of its counsel, the Party is legally compelled to disclose. Each Party shall use reasonable efforts to obtain reliable assurance that confidential treatment will be accorded any Confidential Information so furnished.

(e) **Use in Arbitration**. Each Party may utilize information or documentation furnished by the disclosing Party in any dispute resolution proceeding or in an administrative agency or court of competent jurisdiction addressing any dispute arising under this Agreement, subject to a confidentiality agreement with all participants (including, if applicable, any arbitrator) or a protective order.

(f) **Breach**. The Parties agree that monetary damages by themselves will be inadequate to compensate a Party for the other Party's Breach of its obligations under this Section 29. Each Party accordingly agrees that the other Party is entitled to equitable relief, by way of injunction or otherwise, if it breaches or threatens to breach its obligations under this Section 29.

30. NOTICES. All written legal notices required by this Agreement shall be mailed or delivered as follows:

To Avista:	Avista Corporation Attention: Vice President, Energy Resources and Optimization 1411 East Mission Spokane, WA 99202-2600 Mailing Address: P.O. Box 3727 Spokane, WA 99220-3727
To Potlatch:	Vice President, Pulp & Paperboard Division Potlatch Corporation 805 Mill Road P. O. Box 1016 Lewiston, ID 83501 Fax: 208-799-1586 Vice President and General Counsel Potlatch Corporation 601 West Riverside Ave., Suite 1100 Spokane, WA 99201 Fax: 509-835-1561

Changes in persons or addresses for submittal of written notices by a Party to this Agreement shall be made in writing to the other Party and delivered in accordance with this Section 30. Any verbal notice required hereby which affects the payments to be made hereunder shall be confirmed in writing as promptly as practicable after the verbal notice is given.

31. SETTLEMENT OF LITIGATION.

Potlatch shall dismiss with prejudice its complaint in the United States District Court for the District of Idaho, Case No. CV02-543-C-EJL, and its complaint before the Idaho Public Utilities Commission, Docket No. AVU-E-02-08, upon entry of a final order of the IPUC or court of competent jurisdiction approving the Agreement.

32. EXHIBITS.

This Power Purchase Agreement includes the following exhibits, which are attached and incorporated by reference herein:

Exhibit A - Metering
Exhibit B - Communications
Exhibit C - Description of the Facility

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed by their duly authorized representatives as of the first date herein-above set forth:

POTLATCH CORPORATION

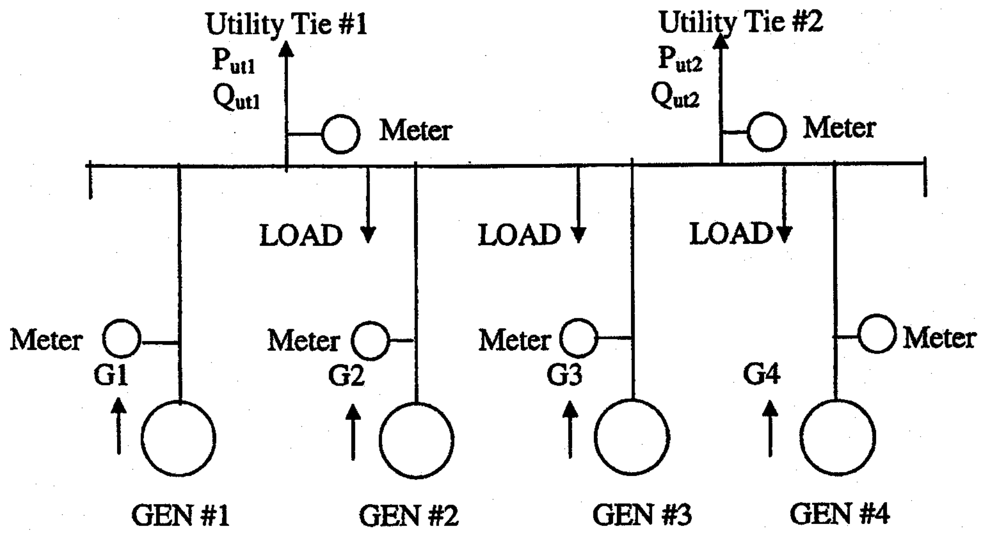
By: ______________________
~~Name: Frank Radke~~
~~Title: Plant Manager, Idaho Pulp & Paperboard Division~~
Name: Harry D. Seamans
Title: Vice President, Pulp & Paperboard Division

AVISTA CORPORATION

By: ______________________ TAD
Name: Gary G. Ely
Title: Chairman, President and Chief Executive Officer

Exhibit A

Metering Specifications, Points and Locations



Simplified Metering Diagram

1.0 Definitions

Whenever used in this Exhibit the following terms shall have the following meanings:

1.1 "Net Facility Power" (G_n). Expressed kW.

1.1.1 For the purposes of this Agreement, the Parties have agreed that Facility Service Power is 125 kW per operating generating unit. Potlatch shall notify Avista when substantial changes are made to the Facility that affect the amount of Facility Service Power. Within a reasonable time the Parties shall select a mutually agreed upon third party auditor and shall share equally the costs of such an audit of Facility Service Power. Unless otherwise agreed, the value determined by such audit shall become the new amount for Facility Service Power for the balance of the term of this Agreement.

1.1.2 For the purposes of this Agreement, the Parties have agreed that Losses are 200 kW.

1.2 "Power Generated" (G_1, G_2, G_3, & G_4). The electric power measured at each operating unit expressed in kW.

1.3 **"Energy Purchased"** (E_p). The amount of energy that Avista purchases from Potlatch generated by the Facility in kWh in each hour.

1.4 **"Energy Sold"** (E_s). The amount of energy that Potlatch purchases from Avista, in kWh in each hour.

1.5 **"Utility Tie Active Power"** (P_{ut}). The total active power delivered to Potlatch, measured at each of the two (2) Pointsof Delivery expressed in kW.

1.6 **"Utility Tie Reactive Power"** (Q_{ut}). The total reactive power delivered to Potlatch, measured at each of the two (2) Points of Delivery expressed in kVAR.

1.7 **"Base Generation Amount"** (G_b). Expressed in kW.

1.8 **"Base Period Demand"** ($D_{kVa\text{-}base}$). Expressed in kVa.

1.9 **"Excess Generation Amount"** (G_e). Expressed in kW.

1.10 **"Excess Period Demand"** ($D_{kVa\text{-}excess}$). Expressed in kVa.

1.11 **"Incremental Generation Amount"** (G_i). Expressed in kW.

1.12 **"Nominal Generation Amount"** (G_{nom}). Expressed in kW.

2.0 General Metering Formulas:

2.1 $P_{ut} = P_{ut1} + P_{ut2}$ (kW)

2.2 $Q_{ut} = Q_{ut1} + Q_{ut2}$ (kVAR) Delivered to Potlatch

2.3 $G_n = G_1 + G_2 + G_3 + G_4 -$ (125kW*(the number of operating generating units)) - (Losses)

2.4 $G_i = G_n - G_{nom}$, where $G_i > 0$
Otherwise $G_i = 0$

3.0 Base Period Power Sales Formula (Time Period in which Base Generation Amount has not been exceeded)

3.1 Energy Sold (E_s) = (P_{ut} + G_n) * Time (kWh)

3.2 Base Period Demand (kVa)

$$D_{kVa-base} = \sqrt{(P_{ut} + G_n)^2 + (Q_{ut})^2}$$

4.0 Excess Period Power Sales Formula (Time Period After The Base Generation Amount Is Exceeded) When The Maximum Excess Generation Amount Is Exceeded Or When Potlatch Uses Excess Generation Amounts To Serve Load And Avista Does Not Purchase Incremental Generation Amounts

4.1 Energy Sold (E_s) = (P_{ut})* Time (kWh)

4.2 Excess Period Demand (kVa)

$$D_{kVa-excess} = \sqrt{(P_{ut})^2 + (Q_{ut})^2}$$

5.0 Excess Period Power Sales Formula (Time Period After The Base Generation Amount Is Exceeded) When The Maximum Excess Generation Amount Is Exceeded Or When Potlatch Uses Excess Generation Amounts To Serve Load And Avista Purchases Incremental Generation Amounts

5.1 Energy Sold (E_s) = (P_{ut}+G_i)* Time (kWh)

5.2 Excess Period Demand (kVa)

$$D_{kVa-excess} = \sqrt{(P_{ut} + G_i)^2 + (Q_{ut})^2}$$

6.0 Excess Period Power Sales Formula (Time Period After The Base Generation Amount Is Exceeded) When Avista Purchases Excess Generation Amounts from Potlatch And Avista Does Not Purchase Incremental Generation Amounts

6.1 Energy Sold (E_s) = (P_{ut}+ G_n)* Time (kWh)

6.2 Excess Period Demand (kVa)

$$D_{kVa-excess} = \sqrt{(P_{ut} + G_n)^2 + (Q_{ut})^2}$$

7.0 Excess Period Power Sales Formula (Time Period After The Base Generation Amount Is Exceeded) When Avista Purchases Excess Generation Amounts from Potlatch And Avista Purchases Incremental Generation Amounts

7.1 Energy Sold (E_s) = (P_{ut}+ G_n)* Time (kWh)

7.2 Excess Period Demand (kVa)

$$D_{kVa-excess} = \sqrt{(P_{ut} + G_n)^2 + (Q_{ut})^2}$$

8.0 Base Period Power Purchase Formula

8.1 Base Generation Purchased (G_b) = G_n * Time (kWh) where $G_i = 0$ or
$G_b = G_{nom}$* Time (kWh) where $G_i > 0$

8.2 Incremental Generation Purchased (G_i) = G_n - G_{nom} * Time (kWh) where $G_i > 0$
otherwise $G_i = 0$

9.0 Excess Period Power Purchase Formula

9.1 Excess Generation Purchased (G_e) = G_n* Time (kWh) where $G_i = 0$
or $G_e = G_{nom}$ where $G_i > 0$
or $G_e = 0$ where Potlatch uses Excess Generation Amounts to serve Load

9.2 Incremental Generation Purchased (G_i) = G_n - G_{nom} * Time (kWh) where $G_i > 0$
otherwise $G_i = 0$

Exhibit B

Communications

1. Verbal Communications

(a) Verbal communications relating to electric power scheduling, generation or load level changes between Potlatch and Avista shall be between the following personnel:

(1) Pre-Schedule (5:30 a.m. to approximately 1:30 p.m. on normal business days):

Avista — Pre-Scheduler (509) 495-4911
Alternate Phone Number: (509) 495-4073

Potlatch — Utility Supervisor (208) 799-1923
Alternate Phone Number: (208) 799-1298

(2) Real-Time Schedule (available 24 hours per day):

Avista — Real-Time Scheduler (509) 495-8534

Potlatch — Utility Supervisor (208) 799-1923
Alternate Phone Number: (208) 799-1298

(b) During normal business hours, all verbal communications relating to interruptions and outages:

Avista — System Operator (509) 495-4105
Alternate Phone Number: (509) 495-4934

Potlatch — Utility Operator (208) 799-1923
Alternate Phone Number: (208) 799-1298

(c) Outside of normal business hours (nights, weekends, and holidays), all verbal communications relating to interruptions and outages shall take place between the following personnel:

Avista — System Operator (509) 495-4105
Alternate Phone Number: (509) 495-4934

Potlatch — Utility Operator (208) 799-1298
Alternate Phone Number (208) 799-1258

Either Party may provide written notice to the other Party setting forth different contact numbers.

Exhibit C

Description of the Facility

1. Unit Number One Description

(a) The unit number one turbine, General Electric serial number 197741, is a nine stage, 3600 RPM, 600 PSIG steam turbine.

(b) The unit number one generator, General Electric serial number 316X188, is nameplate rated at 12,500 kVA.

2. Unit Number Two Description

(a) The unit number two turbine, General Electric serial number 83530, is a six stage, 3600 RPM, 600 PSIG steam turbine.

(b) The unit number two generator, General Electric serial number 6784689, is nameplate rated at 11,188 kVA.

3. Unit Number Three Description

(a) The unit number three turbine, General Electric serial number 197836, is a twelve stage, 3600 RPM, 1250 PSIG steam turbine.

(b) The unit number three generator, General Electric serial number 316X374, is nameplate rated at 41,600 kVA @ 30 PSIG H2.

4. Unit Number Four Description

(a) The unit number four turbine, from ABB order number MB275226, is a 3600 RPM steam turbine.

(b) The unit number four generator, ABB serial number HM300516, is nameplate rated at 66,916 kVA

CASE NO. GNR-E-11-03

PETITION FOR RECONSIDERATION
OF J.R. SIMPLOT COMPANY AND CLEARWATER PAPER
CORPORATION

ATTACHMENT 4

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF A PETITION FILED BY IDAHO POWER COMPANY FOR AN ORDER DETERMINING OWNERSHIP OF THE ENVIRONMENTAL ATTRIBUTES ASSOCIATED WITH A QUALIFYING FACILITY UPON PURCHASE BY A UTILITY OF THE ENERGY PRODUCED BY A QUALIFYING FACILITY.	**CASE NO. IPC-E-04-2** **ORDER NO. 29480**

On February 5, 2004, Idaho Power Company (Idaho Power; Company) filed a Petition with the Idaho Public Utilities Commission (Commission) requesting a Declaratory Order determining ownership of the marketable "environmental attributes" associated with a PURPA qualifying facility (QF) when Idaho Power enters into a long-term, fixed rate contract to purchase the energy produced by that QF. Reference IDAPA 31.01.01.101; Section 210 of the Public Utilities Regulatory Policies Act of 1978 (PURPA). The Commission in this Order declines to grant Idaho Power's Petition for a Declaratory Order.

Background

In June 2003, the Federal Energy Regulatory Commission (FERC) received a Petition for Declaratory Order from PURPA QFs seeking FERC interpretation of its avoided cost rules under Section 210 of PURPA. Specifically, Petitioners sought an Order declaring that avoided cost contracts entered into pursuant to PURPA, absent express provisions to the contrary, do not inherently convey to the purchasing utility any renewable energy credits (RECs) or similar tradable certificates. It was the contention of Petitioners that the power purchase price that the utility pays under such a contract compensates a QF only for the energy and capacity produced by that facility and not for any environmental attributes associated with the facility. Reference American Ref-Fuel Company et al, FERC Docket EL03-133-000.

In an Order issued on October 1, 2003 (105 FERC ¶ 61,004), FERC granted the Petitioners request for a declaratory order, to the extent that the petition asked the Commission to declare that the Commission's avoided cost regulations did not contemplate the existence of RECs and that the avoided cost rates for capacity and energy sold under contracts entered into pursuant to PURPA do not convey the RECs, in the absence of an expressed contractual provision. FERC's Order made the following specific findings:

19. Section 210(a) of PURPA requires the Commission to prescribe rules imposing on electric utilities the obligation to offer to purchase electric energy from QFs. Under Section 210(b) of PURPA, such purchases must be at rates that are: (1) just and reasonable to electric consumers and in the public interest; (2) not discriminatory against QFs; and (3) not in excess of the incremental cost to the electric utility of alternative electric energy. Section 210(d) of PURPA, in turn, defines "incremental costs of alternative electric energy" as "the cost to the electric utility of the electric energy of which, but for the purchases from [the QF], such utility would generate or purchase from another source."

20. The Commission implemented the purchase obligations set forth in PURPA in Section 292.303 of its regulations, 18 CFR § 292.303(a) (2003), which provides:

    Each electric utility shall purchase in accordance with Section 292.304, any energy and capacity which is made available from a qualifying facility. . . .

    Section 292.304, in turn, requires that rates for purchases shall: (1) be just and reasonable to the electric customer of the electric utility and in the public interest; and (2) not discriminate against qualifying cogeneration and small power production facilities. 18 CFR § 292.304(a)(1) (2003). The regulation further provides that nothing in the regulation requires any electric utility to pay more than the avoided costs for purchases. 18 CFR § 292.304(a)(2) (2003). "Avoided costs" are defined as the "incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source." 18 CFR § 292.101(b)(6) (2003).

21. Section 292.304 sets forth what factors are to be considered in determining avoided costs. See 18 CFR § 292.304(e) (2003). The factors to be considered include:

    (1) The utility's system cost data;

    (2) The availability of capacity or energy from a QF during the system daily and season peak periods;

    (3) The relationship between the availability of energy or capacity from the QF to the ability of the electric utility to avoid costs; and

(4) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from the QF.

22. Significantly, what factor is not mentioned in the Commission's regulations is the environmental attributes of the QF selling to the utility. This is because avoided costs were intended to put the utility into the same position when purchasing QF capacity and energy as if the utility generated the energy itself or purchased the energy from another source. In this regard, the avoided costs that a utility pays a QF does not depend on the type of QF, i.e., whether it is a fossil-fuel-cogeneration facility or a renewable-energy small power production facility. The avoided costs rates, in short, are not intended to compensate the QF for more than capacity and energy.

23. As noted above, RECs are relative recent creations of the states. Seven states have adopted renewable portfolio standards that use unbundled RECs. What is relevant here is that the RECs are created by the states. They exist outside the confines of PURPA. PURPA thus does not address the ownership of RECs. The contracts for sales of QF capacity and energy, entered into pursuant to PURPA, likewise do not control the ownership of the RECs (absent an express provision in the contract). States, in creating RECs, have the power to determine who owns the REC in the initial instance, and how they may be sold and traded; it is not an issue controlled by PURPA.

24. We thus grant Petitioners' Petition for Declaratory Order, to the extent that they ask the Commission to declare that contracts for the sale of QF capacity and energy entered into pursuant to PURPA do not convey RECs to the purchasing utility (absent an express provision in a contract to the contrary). While a state may decide that a sale of power at wholesale automatically transfers ownership of the state-created RECs, that requirement must find its authority in state law, not PURPA.

Petition for Declaratory Ruling

Regional organizations, Idaho Power contends, exist to facilitate green energy transactions from resources that have been certified as green energy compliant by those organizations e.g., Bonneville Environmental Foundation (BEF). These entities issue tradable "green tags" to certified renewable energy producers. Green tags are also known as green certificates, renewable energy credits (RECs) and tradable renewable certificates (TRCs). A green tag represents the environmental and other non-power attributes associated with 1 megawatt hour (MWh) of electricity generated from a renewable resource. Some of the QFs from whom Idaho Power anticipates making purchases in the future, the Company contends, have indicated an intention to obtain marketable green tags as a result of entering into contracts with Idaho Power. Green tags avoid the need to package the electricity with its environmental attributes. The tags provide a way in which to "unbundle" the environmental attributes from the electricity and permit the sale of the environmental attributes of renewable generation separately from the electricity generated. In effect, the Company states that green tags are a currency that can be traded to individuals and entities wishing to support "green" energy. Example: Idaho Power Schedule 62 – Green Energy Purchase Program (Case No. IPC-E-00-18, Order No. 28655).

Referencing the foregoing FERC Order, 105 FERC ¶ 61,004, Idaho Power states that FERC suggested that individual states may decide ownership of the green tags. As a result, the Company seeks guidance from the Commission as to ownership of potentially marketable certificates in Idaho.

Idaho Power contends that in Idaho, a utility and its customers confer additional value on QFs by virtue of the long-term, levelized, fixed rate contracts that the utility enters into with the QFs. That value, it asserts, is in addition to the avoided costs paid to the QFs for the energy produced. Vesting the utility with some ownership interest in the green tags, it states, would remunerate the utility for the additional value conferred to the QFs. The QF position, the Company represents, is that QF ownership of the green tags provides the incentive they need to invest in the production of energy from a renewable resource. They assert that the sale of the green tags associated with the generation of green power compensates the QF for the facility's environmental attributes and the additional risks associated with the investment in and the design and operation of a renewable energy resource plant.

Idaho Power Company, in this Petition, requests a declaratory order from the Commission clarifying ownership of these green tags. The "respective arguments" of the Company and QFs are presented in the Company's Petition.

Despite Idaho Power's interest in owning the green tags, the Company acknowledges that retention of those tags by the QF developers may encourage the development of additional green energy resources in Idaho without the need to increase energy purchase prices. Given the heightened public interest in the development of new renewable resources, Idaho Power respectfully recommends that the Commission determine that the developers of such generation facilities receive full ownership rights in any green tags issued to them conditioned upon the requirement that the QF developers who qualify for green tags and from whom Idaho Power purchases energy grant the Company a "right of first refusal" to purchase those tags.

On February 20, 2004, the Commission issued Notices of Petition and Modified Procedure in Case No. IPC-E-04-2. The deadline for filing written comments was March 19, 2004. Timely comments were filed by PacifiCorp, Avista, Bonneville Environmental Foundation (BEF), Exergy Corporation, the Northwest Energy Coalition and Advocates for the West, Bob Lewandowski and Mark Schroeder, and Commission Staff. The Company was provided the opportunity to file Reply Comments and declined to do so. The comments and recommendations of the parties can be summarized as follows:

PacifiCorp

PacifiCorp notes that it has 13 long-term fixed rate contracts with QFs in Idaho, ranging from 80 Kw to 6 MW. None of the QF contracts are levelized. PacifiCorp requests that the Commission deny Idaho Power's request for a "right for first refusal" and instead issue an Order declaring that, pursuant to obligations imposed by PURPA, ownership of all renewable credits associated with energy produced and delivered by a QF pass to the utility that purchases that output of the QF.

Renewable energy credits (RECs) identify generation as having come from a renewable resource. Historically, PacifiCorp contends, QF developers have effectively sold the entire output of their QFs to the purchasing utilities under PURPA-mandated contracts. This bundled output, PacifiCorp contends, includes those characteristics that are now separately identified as renewable energy credits. PacifiCorp characterizes Idaho Power's request as an unbundling of RECs from the overall output of the facilities and the transfer of ownership to the QF without compensation to the purchasing utility. This, it states, is not the intent of the PURPA requirement. Ratepayers and utilities continue to bear the risks, the utility contends, not QFs. To grant ownership of the renewable energy credits to QFs, PacifiCorp maintains, would result in a windfall to QF developers at the expense of ratepayers.

PacifiCorp maintains that any entity that relies on a mandated purchase at a price that is protected from market forces, such as the QFs, is by definition unlikely to be competitive economically. Otherwise, it argues, the project would stand on its own without PURPA protection. To transfer the right to RECs from the purchasing utility to the QF developer, PacifiCorp contends, would exacerbate this perverse incentive.

PacifiCorp contends that utilities and their ratepayers bear the risks associated with QF generation and should receive the benefits arising therefrom. QFs come into existence, it maintains, by choosing not to participate in the market, but rather trigger PURPA, which requires utilities to enter into contracts with them at the utility's avoided costs.

Over the past few years, PacifiCorp notes that a secondary market has developed in the identifying feature of the electricity as having come from the QF as a renewable resource. This new market, it contends, has not created anything that was not there before, i.e., a certificate that shows that renewable power was generated and delivered to the grid; rather, it just permits an owner of a renewable resource to sell the certificate generated by that resource into a nascent market that accords positive financial values to the certificate, which until now has always gone with that power. The Commission in this case, PacifiCorp contends, is being asked to permit QFs to withhold from the purchasing utility the very essence of what, under PURPA, requires the utility to purchase the power from the QF in the first place. Renewable energy credits should not be given to the QF to separately sell, PacifiCorp contends, unless the QFs right to require ratepayers to pay avoided costs for the power is also taken.

Traditional regulatory principles, PacifiCorp contends, dictate that rewards should follow risks, or that the bearer of risks and costs should likewise obtain the benefits. Ratepayers have consistently borne the risk of PURPA-mandated contracts, PacifiCorp argues, and should therefore retain the benefits of those contracts. Ratepayers should not be deprived of a benefit they have always gotten for the past quarter-century under PURPA, simply because a secondary market has developed for that portion of the power that identifies it as having qualified under PURPA in the first place. Any other determination, PacifiCorp contends, would result in double-billing the ratepayer and a windfall for the QF.

PacifiCorp notes that utilities do not voluntarily enter into QF contracts. The price for QF energy is based on avoided costs, not market costs, which PacifiCorp contends Congress has determined adequately compensates QFs that would otherwise be unable to compete in the market. Requiring a utility's ratepayers to pay avoided costs as well as the market rate for renewable energy credits, PacifiCorp contends, would result in increased energy costs.

While acknowledging that Idaho does not currently have a renewable portfolio standard (RPS) program that issues green tags, PacifiCorp notes that such programs are intended to promote renewable energy in the market place by attracting the most efficient renewable energy competitors. Resources must compete against each other rather than against a set level of avoided costs. The approach of PURPA, PacifiCorp contends, is inherently less efficient since it does not require competition among similar resources. For load serving entities, one of the potential future benefits of QF contracts, PacifiCorp contends, is that they can help meet future RPS goals, whether at the national or state level. Typically, load serving entities are required to purchase renewables up to a mandated percentage of total load served.

PacifiCorp contends that QFs have voluntarily withdrawn from the market, and utilities bear the risk of that decision. Idaho Power's requested Order, it states, would be a direct detriment to ratepayers. The benefits should follow risks, and the approach proposed by Idaho Power would set in motion a process whereby QFs can set aside non-power features with positive market value for sale, leaving the ratepayers with generic power equivalent to power generated from a non-renewable resource against the intent of PURPA for utilities to buy cleaner power. Further, PacifiCorp contends that granting RECs to QFs can reduce the effectiveness of future national and/or state renewable programs that intend, in part, to encourage more plant investment for local economic development.

Absent the renewable energy credit, PacifiCorp maintains that power generated by QFs is undifferentiated from other power a utility utilizes to meet its obligation to serve and, therefore, the facility that produces this undifferentiated power should no longer be considered a QF. The REC is an essential aspect of a generation facility's output that resulted in the facility being designated a QF under PURPA in the first place.

Avista

Avista expresses concern that any Order issued by the Commission in Idaho Power's docket will be precedent with respect to other companies. Avista recommends that the Commission's Order be limited in effect to Idaho Power and expressly not apply to Avista Corporation. Alternatively, Avista recommends that the Commission declare that ownership of renewable energy credits associated with QF renewable resources be vested or conveyed to the purchasing utility as a condition of a QF receiving a contract.

QFs located in Idaho, Avista contends, receive a benefit and incentive when they contract to sell to a utility at a long-term, fixed rate contract. The QF developers, it states, receive the benefit of the utility's credit standing, and the likely certainty of a steady continued cash flow over a long period of time. Avista submits that ownership of RECs should remain with the purchasing utility company when the utility is compelled to purchase power from the QF.

Avista contends that the fundamental principle of PURPA is that the power a utility purchases at avoided cost rates from QF projects is intended to displace power from resources that the utility otherwise would have had to construct or purchase. The utility and its customers, Avista contends, should incur no more costs, and receive no less economic benefit from a QF purchase, than a utility-owned generating unit operated for its customers. A purchasing utility, Avista contends, normally expects to acquire all of the attributes and value of the output that it purchases from a QF pursuant to a published avoided cost rate. If the utility does not acquire all of the value of the QF output then, Avista contends, there is not an equivalence of value between a QF project and a comparably sized utility owned resource. Utility customers will receive less value from QF purchases, it maintains, if the monetary benefit of RECs is assigned to the project developer instead of flowing with the power to the benefit of utility customers. It is consistent with the principles of PURPA, Avista argues, that the monetized value of QF renewable resource development be retained by the utility customers in the same manner that the customers would benefit from monetized value of RECs associated with utility generation.

QF development, Avista contends, would not be significantly deterred if renewable energy credits are retained by utilities that purchase power from QFs at published avoided cost rates. QFs are not precluded from taking their electricity output and RECs to the wholesale markets, if they perceive that the wholesale markets offer greater rewards then they will receive at Commission determined avoided cost rates.

The monetary value of RECs, Avista contends, are not preserved to the utility and its customers, if the QF developer retains ownership of the renewable energy credits, even if the QF developer assigns a "right of first refusal" to the utility. The utility and its customers, Avista contends, should be able to benefit from any increase in the value over time of RECs, irrespective of whether the renewable energy credits are associated with utility owned generation, or are acquired by purchase from a QF at published avoided cost rates.

Bonneville Environmental Foundation (BEF)

BEF is a non-profit business that markets green tags representing the environmental attributes of the output of certain renewable power generating facilities. BEF supports and encourages the Commission to adopt the general proposition that the environmental attributes or green tags associated with the output of renewable power facilities are and remain the property of the owner of that facility until and unless the owner consents to a transfer of those green tags to another party. Similar to federal or state tax credits or other incentives employed by the owner to develop its facility, BEF contends that unless otherwise specified, these incentives are intended by the public bodies that established them to be employed in aggregate by a developer of a renewable facility, in recognition that often the economic disincentives act in aggregate to discourage such developments. Thus, the federal government does not demand custody of the green tags from a project that takes advantage of federal tax credits and decelerated depreciation. Thus, a cogeneration facility that uses fossil fuels and may have no green tags to sell is not disqualified from exercising its QF rights under PURPA.

BEF applauds Idaho Power's recognition of the compelling value to the State of Idaho of incenting prospective facility developers to proceed with their renewable projects. Oregon, Washington and other states in which renewable facilities are being actively developed, BEF notes, do not challenge the owners' green tag rights.

BEF parts company with Idaho Power on the narrower question of whether Idaho Power should obtain a "right of first refusal" for the green tags from the facilities in question. BEF understands the Company's reasoning in seeking to protect its customer access to the tags but believes that the market will meet this concern. A right of first refusal, BEF contends, effectively diminishes the market value of the tags to the owners by discouraging a third party from expending the effort and paying the opportunity cost of negotiating to purchase such tags, only to have Idaho Power exercise its right of first refusal. As a marketer, if BEF has an equivalent opportunity to acquire tags from another seller not constrained by such a right of first refusal, BEF will out of necessity prefer the unencumbered tags and seller.

Northwest Energy Coalition and Advocates for the West

The Northwest Energy Coalition is a multi-state association of energy efficiency, clean energy, environmental and other public interest organizations engaged in promoting a clean, reliable and economic energy future for the Pacific Northwest. Advocates for the West is a non-profit conservation law and advocacy center, which supports renewable energy resources and energy efficiency improvements. The commenters concur with the comments of Bonneville Environmental Foundation. BEF's comments, they contend, deserve careful consideration in no small part because BEF markets and sells green tags in Idaho for Idaho Power's green power program.

The commenters appreciate and agree with the general position taken by Idaho Power Company that green tag ownership should stay with project owners. Commenters base their argument on the utility's obligation to price QF power at the utility's avoided cost and the monopsonist power of Idaho Power. The commenters also note that green tags are just one collateral value that PURPA QFs can have, apart from the production of electrons. Methane digesters installed at dairies can improve overall waste management. Canal-drop hydro systems can have independent value to their owners for channel maintenance, water flow management or other reasons. These values are real and separate from the production of electricity at QFs, but a utility could not possibly claim ownership of them.

Regarding Idaho Power's request for "right of first refusal" to purchase green tags from QFs, commenters support BEF's position. Quite simply, they do not believe the Company has presented any legal or other compelling basis to obtain such a right. The Northwest Energy Coalition and the Advocates for the West recommend that the Commission confirm that QF developers own the environmental attributes associated with their projects, free from rights of first refusal.

Exergy Corporation

Exergy Corporation contends that the October 1, 2003, ruling by FERC (Docket No. EL03-133- 00) clearly indicates where and under what circumstances state authority for ascertaining ownership of environmental attributes embedded in renewable programs exists. Under the tenets incorporated into PURPA, whereby the utility is required to purchase energy and capacity only, the environmental attributes are not part of the protocol. Furthermore, Exergy Corporation argues that no Idaho enabling statute exists for a decision on the question of ownership of an environmental attribute by the Idaho Public Utilities Commission.

Exergy Corporation contends that without a specific legislative, regulatory, or legal provision in the Idaho Code or in the Idaho Administrative Rules, there appears to be no legal mechanism to authorize the Commission to create new law. Absent those provisions, without an existing statute to interpret, a directive from the state legislature or a federal mandate, Exergy contends that the Commission cannot implement a decision deleterious to either the generator, the utility, or contrary to FERC and PURPA. Where no state initiated mandatory guidelines are evident, Exergy contends that the environmental attribute remains with the generator.

But the question of whether law exists, Exergy contends, should be moot regardless. Such a law is inappropriate based on the single fact that the QF bears the risk of compliance; therefore, the QF should also have the benefit of environmental attributes. The QF is solely responsible to mitigate pollution consequences, not the customer or utility, and all the liabilities or attributes of that generation lie with the QF.

The inception of the tradable renewable certificates or green tags derived from the environmental attributes, Exergy Corporation contends, was designed towards proliferation of renewable generation sources. The rationale was to provide to the generator, it states, an additional source of income from the potential offset of fossil-fuel emissions and other environmentally sensitive generators. Because renewable generation carries a disproportionately larger installed cost with no ability to pass through fuel risk, any additional inducement results in expanded opportunities to increase the amount of renewable resources.

Exergy Corporation notes that the decision behind the avoided cost rate for a QF in Idaho is based on a natural gas-fired generator. There is no environmental attribute associated with this baseline generator, only capacity and energy. They alone are the basis for the avoided cost rate mandated by the Commission for QFs. No environmental attribute is associated with this mandate. Equally as important, it states, not all QFs are necessarily renewable energy based resources. Therefore, not all QFs in the less than 10 MW category can even demonstrate an environmental attribute.

But there is a more germane argument to be voiced under the concept of Integrated Resource Planning, Exergy Corporation states. Even if the environmental attribute is "stripped" from the renewable resource generation, there still is no rational nexus which purports the generating source to be anything other than nonpolluting. A renewable resource generator stripped of the environmental attribute, is still a nonpolluting generator resource and displacing fueled or hydro generation. No paper commodity will modify the evolution of the electrons produced. Given this transparency, Exergy Corporation contends that the environmental attribute need not be part and parcel of any societal generation mix. The generator is nonpolluting and the potential to offset existing facilities, new emission or social-impact generation is tangible.

An environmental attribute, whether monetized or not, Exergy Corporation contends, is separate from the energy and capacity of generation source. Until such time as the State of Idaho decides to enact legislation essentially (1) forcing PURPA projects to relinquish the environmental attribute to the ratepayer or utility, (2) creating a renewable portfolio standard or (3) implementing another such mandate for renewable resource generation requirements into the IRP of the utilities serving the Idaho customer (and the energy sales price reflects this requirement), the irrefutable answer to the question posed by Idaho Power, Exergy Corporation contends, is that the environmental attribute remains with the QF, unless otherwise mutually agreed upon between QF and purchasing utility.

Bob Lewandowski and Mark Schroeder

Mr. Lewandowski is the current owner of Idaho's first commercial wind power generating facility located south of Interstate 84 between Boise and Mountain Home. Mr. Schroeder currently owns and farms several 1,000 acres contained within the Bell Rapids Irrigation District. Given the cost of electric power to irrigate his farm and its location in a desirable wind resource area, Mr. Schroeder is currently actively planning to construct a large (under 10 MW) wind facility.

Commenters suggest that the Commission should reject Idaho Power's Petition for "right of first refusal" to purchase green tags from QFs. Idaho Power, they contend, has no interest in, or right to, green tags created by QFs.

Commenters dispute the Company's contention that QF developers receive value from Idaho Power for the electricity the QFs generate beyond the purchase price of the energy. The Company's avoided cost rates, they state, are totally unrelated to a QF's internal finances. Avoided cost rates are determined based on the utility's cost of bringing on a new resource. The Company's assertion that QFs receive additional value over and above the avoided cost rates by virtue of 20-year contracts, they contend, is simply wrong. Contract length, they state, is not at all relevant to the question of whether or not the Company should be bestowed with the right of first refusal. The commenters point out that 20-year contracts are not required in surrounding states. Commenters state that it is worth noting that every single state that is adjacent to Idaho has multiple tax incentives, including outright monetary grants to encourage the development of renewable energy projects. The State of Idaho has no such incentives. If the assertions contained in the Company's Petition relative to QFs in Idaho being over compensated remain in the record, the commenters contend that Modified Procedure is inappropriate and request a full evidentiary hearing.

The commenters contend that the Idaho Commission has only limited authority and has no authority to rule on the ownership of green tags. The Commission's jurisdiction, they state, is limited and must be found entirely in its enabling statutes. It is clear, they state, that the Idaho Courts view the Commission's jurisdiction relative to QFs as stemming solely from PURPA and FERC's implementing regulations. It is also clear, they state, that this Commission has no authority other than that conferred upon it by Idaho law or through its role as a state agency regulating utilities under PURPA. What then, they query, are the FERC's PURPA regulations this Commission is charged with implementing that deal with ownership of (including rights of first refusal to) green tags. Simply put, they state that there are none. In fact, they note that FERC has ruled that in order for a state regulatory commission to exercise any authority over green tag ownership there must be a state law bestowing that authority upon the Commission. FERC has made it clear that there is nothing in PURPA or FERC's regulations granting the Commission authority to adjudicate ownership of green tags. FERC has declared that because states created RECs they may regulate how those credits are traded. Idaho has not created RECs, therefore, commenters suggest that there is nothing for the state to regulate. A REC or green tag, the commenters state, is private property owned and created by the QF. It is no different, they argue, from any other ancillary benefit that might accrue to a QF as a result of building a renewable energy resource. Idaho Power's request for right of first refusal, they maintain, is different only in degree from asking for outright ownership. Commenters recommend that Idaho Power's Petition be denied.

Commission Staff

Staff recommends that the Company's Petition for Declaratory Order be denied. Alternatively, should the Commission determine that it has jurisdiction, Staff recommends that the Commission issue a declaratory order stating that mandatory purchases from QFs under PURPA do not convey ownership of any marketable environmental attributes. Accordingly, any environmental attributes associated with QF generation remain with the QF. Staff further recommends that the Commission deny the Company's proposal to require that QF developers from whom Idaho Power purchases energy grant Idaho Power a "right of first refusal" to purchase the environmental attributes associated with the QF facility.

Staff contends that the initial question before the Commission is one of jurisdiction. Does the Commission have the statutory authority and jurisdiction to determine who owns the "environmental attributes" associated with a QF project that requests a PURPA contract and proposes to sell capacity and energy to a regulated utility? If PURPA and FERC rules do not address and do not require a QF developer to sell "environmental attributes" to the purchasing utility, can the Commission in its implementation of PURPA restrict their sale to other parties? If the Commission has the authority under PURPA, should it restrict their sale? Can the Commission require as a PURPA contract condition that a QF grant a purchasing utility a "right of first refusal" to purchase the "green tags" associated with a QF facility?

It is well settled, Staff states, that the Idaho Commission is a creature of statute and derives its general authority vis-a-vis electric utilities from Title 61, Idaho Code. Under State Law, the Commission has authority over retail electric service. Wholesale power transactions are regulated by the Federal Energy Regulatory Commission. All QF sales to an electric utility are wholesale transactions. FERC, in the Order cited by Idaho Power in its Petition (105 FERC ¶ 61,004), states that the contract sale of QF capacity and energy entered into pursuant to PURPA does not convey renewable energy credits to the purchasing utility (absent an express provision in the contract to the contrary). FERC notes that RECs are relatively recent creations of the States and suggested that states, in creating RECs, have the power to determine who owns the credit in the initial instance, and how they may be sold and traded. "It is not," FERC states, "an issue controlled by PURPA." Staff notes that Idaho is not a state that has established a renewable energy portfolio standard for electric utilities. Nor is it a state that has by legislation created green certificates, green tags, renewable energy credits or tradable renewable certificates or established a market for same. Nor is Idaho a state that has provided tax incentives or credits for the development of renewable energy. In short, Staff contends, there appears to be no hook that gives the Commission jurisdiction over "environmental attributes," not under PURPA or federal law (including the Energy Policies Act of 1992), and not under Title 61 of the Idaho Code.

In the context of PURPA wholesale transactions, Staff notes that FERC has barred state commissions from establishing different wholesale prices for otherwise qualified cogeneration or small power production facilities. 18 C.F.R. § 292.304(a)(ii). Accordingly, contracts for renewable resources cannot be at a higher price than for non-renewable resources, nor can the requirements of contract be different. Discrimination either directly or indirectly is not permitted.

Arguably, what Idaho Power proposes, Staff contends, is an impermissible "taking" of property. The Fifth Amendment of the U. S. Constitution states "nor shall private property be taken for public use without just compensation." Idaho Power requests a Commission Order granting the utility by regulatory fiat a "right of first refusal." It proposes no compensation to the QF for the right. Electric utility purchases of energy and capacity from PURPA QFs are mandatory. 18 C.F.R. § 292.303(a). The environmental attributes associated with renewable QF projects, Staff contends, are currently separate from the capacity and energy sold to Idaho utilities. They are not, Staff contends, bundled together as a matter of law. Nor is the cost to purchase environmental attributes included in an Idaho utility's avoided cost. To the extent those attributes have value and provide additional developer incentive, Staff believes they should remain with the developer. At this time, Staff contends that no argument has been advanced nor authority cited to justify or require placing any regulatory restriction by this Commission on their ownership.

COMMISSION FINDINGS

The Commission has reviewed the filings of record in Case No. IPC-E-04-2. We have reviewed the comments of PacifiCorp and Avista, the comments and recommendations of the Commission Staff, and the comments of other interested parties. Based on our review, we continue to find it reasonable to process this case pursuant to Modified Procedure. IDAPA 31.01.01.204.

Idaho Power in this case requests a Declaratory Order regarding the ownership of the marketable "environmental attributes" or green tags associated with PURPA qualifying facility (QF) projects when Idaho Power enters into a long-term, fixed rate contract to purchase the renewable energy produced by that QF. It is the Company's recommendation that the ownership of green tags be confirmed in the QF and as a condition of contract that the utility be granted a "right-of-first refusal" to purchase the tags. Other parties recommend a variant, expansion or denial of the Company's requested relief.

All commenters recommend for different reasons that the ultimate relief requested by Idaho Power, i.e., that the Company be provided a "right of first refusal" to purchase the environmental attributes or green tags associated with required QF purchases, be denied. PacifiCorp and Avista maintain that the environmental attributes or green tags associated with renewable resources are the property of the purchasing utility. The Bonneville Environmental Foundation, Northwest Energy Coalition and Advocates for the West recommend that the Commission confirm that QF developers own the environmental attributes associated with their projects, free from rights of first refusal. Exergy Corporation, Bob Lewandowski and Mark Schroeder and Commission Staff contend that the Commission has no jurisdiction or authority stemming from either PURPA, FERC implementing regulations or Idaho state law to grant the requested relief. Should the Commission decide not to dismiss Idaho Power's Petition, Mr. Lewandowski and Schroeder contend that the Company's Petition is not appropriate for Modified Procedure and request that the Commission schedule an evidentiary hearing.

We find that the issue presented by Idaho Power in its Petition does not present an actual or justiciable controversy in Idaho and is not ripe for a declaratory judgment by this Commission. Declaratory rulings are appropriate regarding the applicability of any statutory provision or of any rule or order of this Commission. *See* IDAPA 31.01.01.101; Uniform Declaratory Judgment Act, *Idaho Code* 10-1201 *et seq.* A declaratory ruling contemplates the resolution of prospective problems. The rights sought to be protected by a declaratory judgment may invoke either remedial or preventive relief; it may relate to a right that is only yet in dispute or a status undisturbed but threatened or endangered; but in either event it must involve actual and existing facts. *Idaho Code Supreme Court in Harris v. Cassia County,* 106 Idaho 513, 516-517, 618 P.2d 988 (1984). We find that none of the predicates are present in this case. In making this finding, the Commission notes that FERC on April 15, 2004 (Docket EL03-133-001, 107 FERC ¶ 61,016) denied rehearing of its earlier October 1, 2003 Order (105 FERC ¶ 61,004). We note also that the State of Idaho has not created a green tag program, has not established a trading market for green tags, nor does it require a renewable resource portfolio standard.

While this Commission will not permit the Company in its contracting practice to condition QF contracts on inclusion of such a right-of-first refusal term, neither do we preclude the parties from voluntarily negotiating the sale and purchase of such a green tag should it be perceived to have value. The price of same we find, however, is not a PURPA cost and is not recoverable as such by the Company. Recovery of those expenses will be reviewed as are all other non-PURPA costs.

CONCLUSIONS OF LAW

The Idaho Public Utilities Commission has jurisdiction over Idaho Power Company, an electric utility, pursuant to the authority and power granted it under Title 61 of the Idaho Code and the Public Utility Regulatory Policies Act of 1978 (PURPA).

The Commission has authority under PURPA and the implementing regulations of the Federal Energy Regulatory Commission (FERC) to set avoided costs, to order electric utilities to enter into fixed term obligations for the purchase of energy from qualified facilities, and to implement FERC rules.

ORDER

In consideration of the foregoing and as more particularly described above, IT IS HEREBY ORDERED and the Commission does hereby decline to grant Idaho Power's Petition for a Declaratory Order. IDAPA 31.01.01.101.

IT IS FURTHER ORDERED and the Commission does hereby deny any and all other relief requested by the commenting parties as may be related to the "environmental attributes" associated with QF renewable energy.

THIS IS A FINAL ORDER. Any person interested in this Order (or in issues finally decided by this Order) may petition for reconsideration within twenty-one (21) days of the service date of this Order with regard to any matter decided in this Order. Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. See *Idaho Code* § 61-626.

DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 27th day of April 2004.

Paul Kjellander

PAUL KJELLANDER, PRESIDENT

Marsha H. Smith

MARSHA H. SMITH, COMMISSIONER

Dennis S. Hansen

DENNIS S. HANSEN, COMMISSIONER

ATTEST:

Jean D. Jewell

Jean D. Jewell
Commission Secretary

vld/O:IPCE0402_sw

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on the 8th day of January, 2013, a true and correct copy of the within and foregoing PETITON OF RECONSIDERATION OF J.R. SIMPLOT COMPANY AND THE CLEARWATER PAPER CORPORATION was served as shown to:

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