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DONOVAN E. WALKER
Lead Counsel
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June 29, 2012

VIA HAND DELIVERY

Jean D. Jewell, Secretary
Idaho Public Utilities Commission
472 West Washington Street
Boise, Idaho 83702

Re: Case No. GNR-E-11-03
PURPA SAR and IRP Methodologies – Idaho Power Company's Rebuttal Testimony

Dear Ms. Jewell:

Enclosed for filing in the above matter are nine (9) copies each of the testimonies of M. Mark Stokes and Tessia Park. One copy of each of the aforementioned testimonies has been designated as the "Reporter's Copy." In addition, a disk containing Word versions of the testimonies is enclosed for the Reporter.

Very truly yours,

Donovan E. Walker

DEW:csb
Enclosures

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IDAHO PUBLIC
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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE COMMISSION'S REVIEW OF PURPA QF CONTRACT PROVISIONS INCLUDING THE SURROGATE AVOIDED RESOURCE (SAR) AND INTEGRATED RESOURCE PLANNING (IRP) METHODOLOGIES FOR CALCULATING PUBLISHED AVOIDED COST RATES.	CASE NO. GNR-E-11-03

IDAHO POWER COMPANY

REBUTTAL TESTIMONY

OF

M. MARK STOKES

Q. Please state your name and business address.

A. My name is M. Mark Stokes and my business address is 1221 West Idaho Street, Boise, Idaho.

Q. Are you the same M. Mark Stokes that submitted direct testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. In my rebuttal testimony, I will address the following items:

1. I will respond to recommendations to change the source of the natural gas price forecast used to set avoided cost rates. In addition, I will discuss the sensitivity of each of the avoided cost methodologies to changes in natural gas prices.

2. I will respond to statements made by others in direct testimony supporting the continued use of the Surrogate Avoided Resource ("SAR") methodology and provide additional information supporting my recommendation to abandon the use of the SAR methodology.

3. I will respond to questions raised by others in direct testimony regarding Idaho Power Company's ("Idaho Power" or "Company") proposed Hourly Incremental Cost methodology and provide additional support for the adoption of this methodology to set avoided cost rates.

4. I will also respond to recommendations made by others regarding contract term, the published rate eligibility cap, the avoided cost of capacity and energy, the use of a carbon adder in avoided cost rate calculations, the security deposit for liquidated damages, and the need to litigate Integrated Resource Plans ("IRP").

5. I will describe why the electric utilities that purchase energy from a Qualifying Facility ("QF") should also receive the associated environmental attributes and/or Renewable Energy Credits ("RECs") associated with the purchase of that energy.

6. Finally, I will present Idaho Power's proposed Schedule 73 to address the QF contracting process.

I. NATURAL GAS PRICE FORECAST

Q. Several parties have filed testimony in support of using a natural gas price forecast developed by the Energy Information Administration ("EIA") in the calculation of avoided cost rates. Do you support this recommendation?

A. Yes. I believe using the EIA forecast and updating it annually in July of each year is a step in the right direction. However, it does not resolve the underlying problem that the natural gas price forecast assumption has too significant of an impact on the avoided cost rates produced by the SAR methodology.

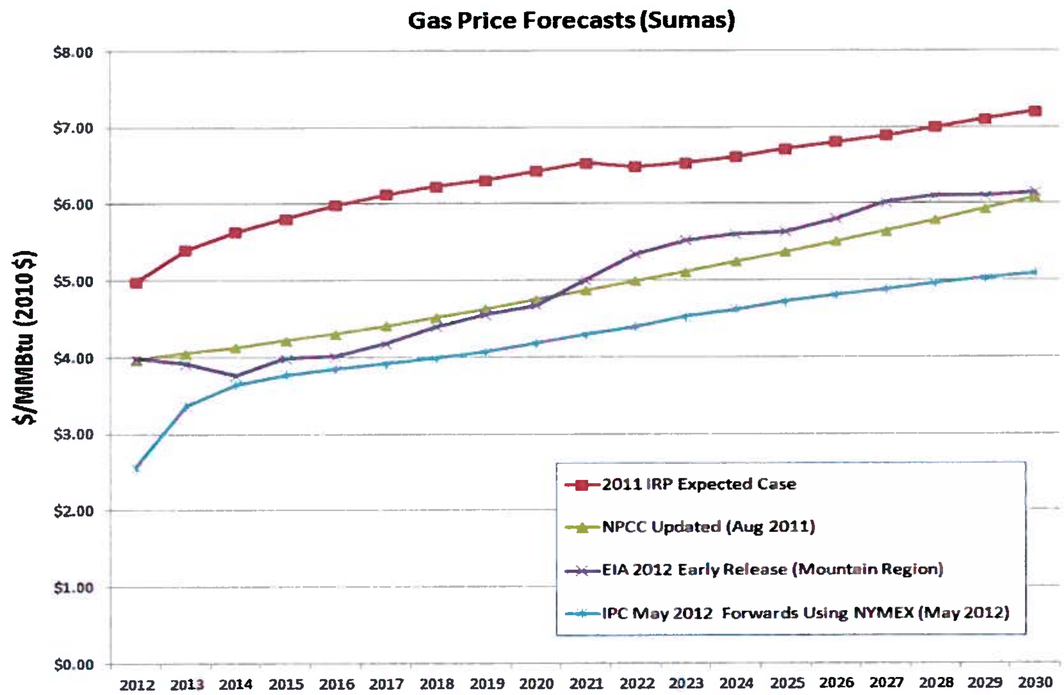
In addition, current and near-term market prices for natural gas are approximately half of the EIA forecast presented in Exhibit No. 301 of the Direct Testimony of Idaho Public Utilities Commission Staff ("Staff") witness Cathleen McHugh. This EIA forecast was released in January 2012 and is already off by approximately 50 percent in the near term. This highlights the underlying problem that the avoided cost rates can become out of date rather quickly and, further, avoided cost rates determined using the SAR methodology compound this problem because they are overly sensitive to the natural gas price assumption used in the model. In addition to establishing a better, more accurate source for the natural gas price forecast, I believe it would be of greater benefit to adopt an avoided cost methodology that is less sensitive to the natural gas price assumption, such as the Hourly Incremental Cost methodology proposed by Idaho Power.

Q. Do you have any proposed modifications to Staff's recommendation to use the EIA gas forecast and update it annually in July of each year?

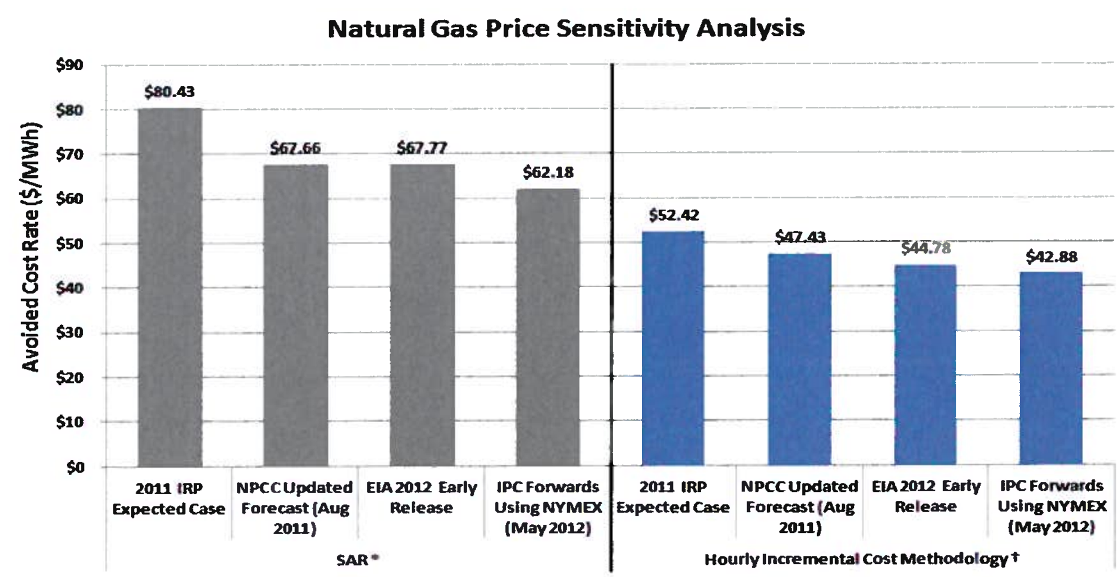
A. Yes. EIA releases an annual natural gas price forecast in the spring of each year. In addition, during the interim months between EIA's annual forecast, EIA releases a short-term forecast. Idaho Power recommends that the short-term forecast also be adopted. This will help to somewhat address the problem identified earlier in my testimony where I describe how the EIA annual forecast can rapidly become outdated and inaccurate in a rapidly shifting natural gas market. As previously noted, the EIA gas forecast released in January 2012 is already more than 50 percent off in the near term. By incorporating EIA's monthly updates, this inaccuracy can be somewhat mitigated on a monthly basis, rather than allowing an entire year to pass with the corresponding inaccuracy transferred to avoided cost rates.

Q. Is the Hourly Incremental Cost methodology proposed by Idaho Power in this case less sensitive to changes in the natural gas price forecast than the SAR methodology?

A. Yes, it is. Idaho Power has compared the gas price sensitivity of the SAR methodology and Idaho Power's Hourly Incremental Cost methodology. Both methodologies were used to calculate avoided cost rates for a base load resource using Idaho Power's 2011 IRP natural gas price forecast (August 2010), the Northwest Power and Conservation Council's updated forecast (August 2011), the EIA forecast (January 2012), and current NYMEX forward prices. This series of natural gas price forecasts occurred over a time period where prices were falling and are shown in the following figure.



The results of this comparison are provided in the figure below and show the 20-year, levelized avoided cost rates from the SAR methodology vary from $80.43 to $62.18 (23 percent) and the Hourly Incremental Cost methodology varies from $52.42 to $42.88 (18 percent).



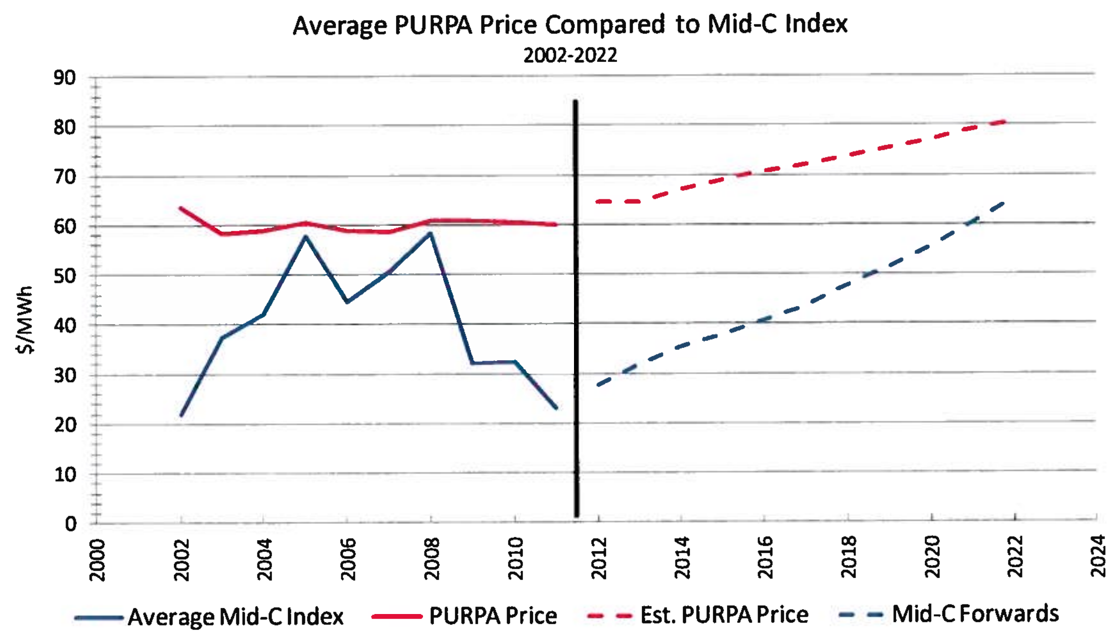
Notes: * SAR model run using Sumas natural gas forecast
† Hourly Incremental Cost Methodology using April 2012 load forecast and no carbon

These results show that the SAR methodology is more sensitive to the natural gas price assumption than Idaho Power's proposed Hourly Incremental Cost methodology. Natural gas prices have historically been the most volatile of all the inputs used to set avoided cost rates. Using a methodology that is less sensitive to the gas price forecast will likewise reduce the volatility of avoided cost rates.

II. SAR METHODOLOGY

Q. Do you agree with the statement made by Dr. Don Reading that avoided cost rates calculated using the SAR methodology "have been remarkably accurate in hindsight." (Reading Direct, p. 7, l. 8.)

A. No, I do not. As I stated in my direct testimony, historically there has been a significant difference between the prices paid to QF resources on Idaho Power's system and the Mid-C market index to the direct and substantial detriment of Idaho Power's customers and, on a forward looking basis, there continues to be a significant difference between QF prices and the Mid-C forward market price. This difference is illustrated in the following figure:



While the Mid-C index does not represent an avoided cost rate, it does highlight the harm done to Idaho Power's customers when Idaho Power has excess QF energy which must be sold into the market at a substantial loss.

Q. Why do you believe avoided cost rates determined by the SAR methodology are not accurate?

A. The concerns I have are not limited to the SAR methodology, but any proxy method, which is why I believe the SAR methodology should be abandoned and not just modified, as recommended by others in this proceeding.

The SAR methodology is currently based on the estimated cost of a utility building, owning, and operating a combined-cycle combustion turbine ("CCCT"), and does not account for all of the unique characteristics of the various types of QF resources, including the availability of generation during system peak loads. In addition, the methodology does not take into consideration that QF resources are not economically dispatched in the same fashion as utility-owned resources as under the Public Utility Regulatory Policies Act of 1978 ("PURPA"), Idaho Power has a "must purchase" obligation. For these reasons, the product a QF resource delivers is very different from the product produced by a utility-owned resource such as a CCCT, and is not as valuable to the utility with its obligation to serve load in a least-cost, reliable manner.

The high rates produced by the SAR methodology and the subsidies available to many QF developers in the form of investment and production tax credits as well as renewable energy certificates are the primary drivers in why Idaho Power has recently seen a landslide in QF development. While the Idaho Public Utilities Commission ("Commission") cannot control state and federal subsidies and tax incentives, it can remove some of the financial incentive which is harming Idaho Power customers, and was never the purpose nor intent of PURPA, by abandoning the SAR methodology completely.

Q. Do you have any other basis for Idaho Power's recommendation that the SAR methodology be abandoned for the purposes of calculating Idaho Power's avoided cost rates paid to PURPA QFs?

A. Yes. Based upon Idaho Power's direct testimony, and its March 12, 2012, Motion for a Temporary Stay of its Obligation to Enter into New Power Purchase Agreements with Qualifying Facilities filed in this matter, the Commission made findings "that the methodologies previously approved by this Commission, as utilized and applied by Idaho Power, do not currently produce rates that reflect Idaho Power's avoided cost and are not just and reasonable, nor in the public interest." Order No. 32498. Idaho Power believes that based upon its system configuration, costs, and operations - including the large amount of PURPA generation that currently exists on its system - that the SAR methodology is no longer capable of providing rates that are just and reasonable, nor in the public interest. The resulting rates from the SAR methodology do not result in rates that hold Idaho Power's customers indifferent as to whether they are paying for power generated by a QF or that which is otherwise generated or acquired by the Company. While it may, or may not, be appropriate to continue the use of the SAR methodology for Idaho's other investor-owned utilities, it is no longer appropriate to continue its use for Idaho Power for the reasons set forth by Idaho Power in this proceeding.

Q. Several witnesses in this case have filed testimony advocating the continued use of the SAR methodology because of its transparency and simplicity. Do you agree with this?

A. No, I do not. I believe these statements were made only because the SAR methodology has been used for a long period of time in Idaho and people have become familiar with it. Just because the SAR methodology has been used in Idaho for a number of years does not necessarily mean that the methodology is transparent or simple. In a recent Public Utility Commission of Oregon case involving avoided cost rates, Public Utility Commission of Oregon staff rejected the SAR methodology on the basis of its complexity and lack of transparency, particularly the tilting rate capital calculation contained in the model.

Q. On page 8 of his direct testimony, Dr. Reading references a National Economic Research Associates ("NERA") survey that is mentioned in the Direct Testimony of Idaho Power witness William Hieronymus. What conclusion does Dr. Reading make regarding this survey?

A. Dr. Reading points out that the survey results showed 14 states out of 49 surveyed used some form of the proxy method. Dr. Reading's conclusion from this data is that it "indicates the SAR method is widely accepted as valid method [sic] for determining avoided cost rates."

Q. Do you agree with Dr. Reading's conclusion?

A. No, for two primary reasons. First, the survey was regarding the use of a proxy method, not the specific SAR methodology as it has been used in Idaho. Dr. Reading makes a big leap to get to his conclusion that the SAR methodology is somehow valid because a few states use some form of a proxy method. Second, while the survey does indicate some states use a form of the proxy method (14 out of 49 or 29 percent), it can also be stated that 35 out of 49 states (or 71 percent) have chosen other methodologies for determining avoided cost rates. Dr. Reading chooses to ignore this conclusion, which is in fact compelling data to suggest that a proxy method is not the best way to calculate a utility's avoided costs.

III. HOURLY INCREMENTAL COST METHODOLOGY

Q. Do you believe that levelized avoided cost rates available to QFs should be the same or very similar to the per megawatt-hour ("MWh") production cost of a utility-owned resource as Dr. Reading suggests?

A. No, I do not. There are many reasons that I will elaborate upon in my testimony as to why the two cost figures would not match or even be close, the most important of which is that a utility-owned resource will be dispatched based upon need, system reliability, and economics while, currently, a QF resource is incented to generate as much as possible in all months of the year regardless of need, cost, or economic considerations because the electric utility has a "must purchase" obligation under PURPA.

Throughout his direct testimony, Dr. Reading is critical of any changes to avoided cost rate calculations proposed by parties to this case on the grounds that a proposed change "does not put the QF on an equal cost footing with the utility's own resources." (Reading Direct, p. 13, l. 2). Furthermore, on page 5 of his direct testimony, Dr. Reading quotes the following passage from Commission Order No. 15746 (1980):

> This Commission endorses the policy of having each utility pay its full avoided cost when purchasing power from cogenerators and small power producers. Such a price will bring about the equilibrium solution typical of a competitive market where the marginal cost of all firms ***producing a like product*** is equal. Anything less will fail to bring about the condition of a free, competitive market and will leave the utility, as the sole buyer, in a position to dictate price as it sees fit. (*Emphasis added.*)

I have added the emphasis in the passage above because I do not believe QF generation and utility-owned generation are "like products" because they are not bound by the same economic constraints. In addition, I do not believe the SAR methodology is capable of capturing these differences.

Further, the definition of avoided cost is "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 C.F.R. § 292.101(b)(6). Avoided cost must additionally leave a utility's customers neutral or indifferent as to whether the electricity was generated by the utility or the QF. Order No. 32262, 18 C.F.R. § 292.304. Customers are not being held indifferent and are paying much more for QF generation under the SAR avoided cost rates than other available power the Company could generate itself or otherwise acquire.

Q. On page 34 of Dr. Reading's testimony, he provides a chart showing four different levelized costs. He goes on to describe the costs as being dramatically different, and questions whether Idaho Power's proposed Hourly Incremental Cost methodology produces a realistic estimate of avoided cost. Do you agree with Dr. Reading's assessment?

A. No, I believe the differences between the levelized costs reported by Dr. Reading can be easily explained and serve to highlight some of the differences between a QF and a utility-owned resource. Specifically, I am going to focus on the difference between Idaho Power's 2011 IRP estimated levelized cost of $98 per MWh for a utility-owned and operated CCCT and the Hourly Incremental Cost methodology's avoided cost rate of $47.40 per MWh for a base load QF resource. An explanation of the factors and assumptions behind these levelized cost estimates demonstrates the avoided cost rates calculated under the Hourly Incremental Cost methodology are not dramatically different from estimated utility costs to build and operate a resource, after taking into account characteristics of the utility-owned resource relative to the QF resource.

Q. Please explain further the differences between the levelized costs of a QF resource and one which is utility-owned and operated.

A. A key difference between these cost estimates is the assumed annual capacity factor for the two resources. The 2011 IRP estimate assumes a 270 megawatt ("MW") CCCT economically dispatched at a 65 percent annual capacity factor, while the Hourly Incremental Cost methodology base load resource example assumes a QF resource operating at a 92 percent annual capacity factor. With a much higher capacity factor, the QF delivers energy during a considerable number of hours during which the

Company's costs to operate its existing resources are relatively low. Consequently, the costs the QF allows Idaho Power to avoid during these hours are also relatively low. If the QF were dispatchable and only operated when economical and in the same manner the utility would operate its own resources (65 percent annual capacity factor), the Hourly Incremental Cost methodology's levelized rate would increase by approximately $13 per MWh.

A second difference relates to the period over which the cost is levelized. The 2011 IRP cost is levelized over a 30-year period, while the $47.40 per MWh calculated under the Hourly Incremental Cost methodology is levelized over a 20-year period. Extending the Hourly Incremental Cost methodology analysis to 30 years and then leveling the costs over an additional 10 years increases the proposed methodology's estimate by approximately $6 per MWh.

Another factor explaining the difference between the cost estimates involves the natural gas price forecast used for each. Operating costs for a CCCT in the 2011 IRP are based on earlier forecasts of nominal natural gas prices at Sumas reaching approximately $13 per MMBtu by 2030. By comparison, the more recent August 2011 Northwest Power and Conservation Council fuel price forecast used in the Hourly Incremental Cost methodology has nominal Sumas prices reaching only about $9 per MMBtu by 2030. While part of the Hourly Incremental Cost methodology's appeal is its lower sensitivity to changes in natural gas prices, the use of the higher 2011 IRP natural gas forecast in the proposed methodology still produces an increase of approximately $5 per MWh in the estimated levelized cost.

It is also important to note that the Hourly Incremental Cost methodology defers avoided capacity costs until the Boardman to Hemingway transmission line is operational in 2016. In contrast, the 2011 IRP estimate for a CCCT begins accounting for capacity costs when the plant is placed in-service. For the sake of comparison, if the avoided capacity costs in the Hourly Incremental Cost methodology were assumed to begin in 2013, the proposed methodology would yield an estimated levelized cost about $3 per MWh higher.

Q. Are there other differences between a utility-owned CCCT and a QF resource that differentiate the value each type of resource provides?

A. Yes, there are other differences between a utility-owned resource and a QF resource; however, they are more qualitative. First, a utility-owned CCCT is able to provide operating reserves necessary for the reliable operation of the electrical system. This is particularly important for Idaho Power because of the increasing amounts of variable and intermittent generation being added to the system. An intermittent QF generator, on the other hand, increases the amount of operating reserves a utility must have available.

Second, a utility-owned CCCT can be undesignated as a network resource and utilized to source firm, off-system sales, when economical, which benefits customers by offsetting other power supply costs. The ability to provide operating reserves and source firm, off-system sales are directly related to the fact that a utility-owned CCCT is dispatchable, while a QF resource is not.

Finally, new utility-owned resources are scrutinized during public regulatory processes for the development and acknowledgment of the Company's IRP and filing for a Certificate of Public Convenience and Necessity ("CPCN") where it must be demonstrated to regulators, customers, and other stakeholders that the new resource will be not only used and useful but also least cost. This helps to ensure that any new resource selected is well suited to the electrical system and customer needs. For example, the need for a resource in 2012 like Langley Gulch power plant was first introduced and vetted in the Company's 2004 IRP, and subsequently in the Company's 2006, 2009, and 2011 IRPs. In addition, it was subject to a fully contested CPCN proceeding at the Commission in Case No. IPC-E-09-03. In contrast, Idaho Power is forced to take whatever QF generation is proposed to it with no regard to customer need, the QF's impact on the reliable operation of Idaho Power's system, or the cost that QF generation imposes on Idaho Power's customers. Idaho Power was obligated to sign 294 MW of QF wind contracts during a two-month period in late 2010 without any evaluation or scrutiny given to whether those resources were needed, or how they would impact customer rates or the reliable operation of Idaho Power's electrical system.

Q. Based on your review, what do you conclude from the cost comparison chart shown on page 34 of Dr. Reading's testimony?

A. Dr. Reading asserts that the magnitude of the difference in the levelized costs "calls into question the claims that the proposed method is a realistic estimate of the Company's avoided cost." (Reading Direct, p. 34, l. 4.) Based on review of the levelized costs presented, and the inputs and assumptions used for each, I believe the differences in the costs can be easily explained and highlight why a QF resource does not provide the same value as a utility-owned resource. It is for these same reasons that the SAR methodology, or any other proxy method, is incapable of accounting for all the differences in resource characteristics and is therefore not able to produce accurate, or appropriate, avoided cost rates.

Q. Would you characterize Idaho Power's proposed Hourly Incremental Cost methodology as transparent and simple?

A. Yes, I would. In the Hourly Incremental Cost methodology, the AURORA model is used to determine the dispatch of utility-owned resources; beyond that, all other information and calculations are done in an Excel spreadsheet, which I believe is very transparent. The main Excel worksheet is large, but only because it performs the same calculation for every hour of the contract term.

As far as simplicity, I have had the opportunity to become familiar with the spreadsheet and the methodology over the past few months and believe it is simpler and more transparent than the SAR model. Others likely do not share this view because they have not yet spent much time working with it. While I was not involved with avoided cost rates when the SAR methodology was implemented, my guess is similar feelings were also expressed at that time because it was new to everyone.

Q. Do you believe Staff has thoroughly reviewed the Hourly Incremental Cost methodology and spreadsheet?

A. Yes, I do. In fact, based on the discovery questions Idaho Power received from Staff, I would say Staff did a very thorough review of the methodology and supporting data submitted by Idaho Power.

Q. After reviewing the Hourly Incremental Cost methodology, is Staff supportive of the method Idaho Power is proposing?

A. Yes, they are. Beginning on page 8 and continuing through page 13 of his direct testimony, Staff witness Sterling discusses various aspects of the Hourly Incremental Cost methodology proposed by Idaho Power. The following statements are taken from Mr. Sterling's testimony and are representative of the support expressed for the proposed methodology:

> I believe that Idaho Power has properly focused on the <u>incremental costs</u> that the utility would incur as the basis for determining avoided costs. (Sterling Direct, p. 10, l. 21.)

> I believe that the IRP methodology as proposed by Idaho Power conforms more closely with FERC's definition of avoided cost than the way in which Idaho Power has employed the methodology in the past. (Sterling Direct, p. 11, l. 1.)

> I believe that the methodology as proposed by Idaho Power is acceptable, and as I stated previously, an improvement over the currently-accepted methodology. (Sterling Direct, p. 13, l. 8.)

Q. Although supportive of the Hourly Incremental Cost methodology proposed by Idaho Power, Staff is still recommending the SAR model be used to establish published rates. Do you agree with this?

A. No, I do not. There are many reasons for abandoning the SAR methodology that I expound on in both my direct and rebuttal testimony, and I will not reiterate them all here. However, I would like to emphasize that I believe it would be an unnecessary administrative burden to continue to use the SAR methodology for published rates when a single method could be adopted and used to set both published and negotiated avoided cost rates.

Q. Does the Company have any changes or updates to the Hourly Incremental Cost methodology or pricing that it would like to submit?

A. Idaho Power has no proposed changes to the methodology itself as such is proposed in the Direct Testimony of Karl Bokenkamp. However, the Company does have updated current avoided cost prices derived from the Hourly Incremental Cost methodology. Submitted as Exhibit No. 9 to my rebuttal testimony are updated current prices for the four representative QF generation types that coincide with and replace the current prices reflected in Corrected Exhibit No. 8 previously submitted with witness Bokenkamp's pre-filed direct testimony. The updated current prices in my Exhibit No. 9 were derived using the EIA natural gas forecast recommended by Commission Staff and Idaho Power's updated April 2012 load forecast. The updated pricing takes into account recent events, such as the removal of loads associated with Hoku Materials, Inc., as well as other updated adjustments.

IV. SAR METHODOLOGY MODIFICATIONS

Q. Although you propose abandoning the SAR methodology in favor of Idaho Power's Hourly Incremental Cost methodology for both published and negotiated rates, do you have any comments on the modifications to the SAR methodology proposed by other witnesses?

A. Yes, I do. As an initial matter, I must reiterate that Idaho Power believes the Commission should completely abandon the use of the SAR methodology for determining avoided cost rates. For all the reasons explained in my direct testimony and elsewhere in my rebuttal testimony, the Company believes the Hourly Incremental Cost methodology is a better, more accurate manner in which to determine avoided costs. That said, if the Commission elects to retain the SAR methodology, I would recommend a number of changes to that methodology, including updating the index used to determine natural gas prices. As I previously stated, several witnesses support using the EIA natural gas price forecast and updating it on an annual basis. Because of the frequency of updates, I believe this would be better than continuing to rely on the Northwest Power and Conservation Council forecast; however, it still does not resolve the primary problem of the SAR methodology being overly sensitive to changes in the natural gas price assumption.

Q. In his direct testimony, Staff witness Sterling agrees with your proposal to use a simple-cycle combustion turbine ("SCCT") to determine the avoided cost of capacity for all QF resource types. (Sterling Direct, p. 16, l. 24.) Could an SCCT be used in the SAR methodology as well?

A. Yes, I believe it could be if just the capital and fixed costs of an SCCT were used to determine the capacity portion of the avoided cost rate. The energy component would still require using the heat rate and other variable operations and maintenance assumptions appropriate for a CCCT.

Q. In her direct testimony, Staff witness McHugh proposes to apply the "first deficit year" concept to both the capacity and energy components of avoided cost rates (McHugh Direct, p. 9, l. 10). Do you agree with her proposal?

A. Yes, with one recommended change. As I understand the proposal, capacity payments would be removed from the avoided cost rate until the month the first uncommitted resource is identified in each utility's IRP. For the avoided cost of energy payments, deductions from the rate would be made to account for transmission wheeling costs and losses until the first month an energy deficit occurs in each utility's IRP. In general, I support this proposal because I believe this treatment of capacity costs is an appropriate way to account for the ability of a QF to come on-line at any time irrespective of a utility's need. For the energy component, transmission wheeling and losses are real costs that result from having to sell surplus energy into the market and, therefore, I am also supportive of this concept with one modification.

Q. What is your recommended modification to Staff's proposal with regard to avoided cost of energy payments?

A. Energy surplus/deficit positions are determined on a monthly basis in the IRP. Therefore, I propose that deductions for wheeling and losses be made for any month the utility is surplus throughout the term of the QF contract, not just until the first deficit month is reached. A utility factors in wheeling and transmission loss costs as part of making the decision of whether to dispatch a utility-owned resource. Because a QF resource is incented to deliver as much energy as it can to the utility during all months of the year, I believe it would be appropriate to account for these costs for any month the utility is surplus throughout the term of the contract.

Q. Canal company witness Schoenbeck proposes numerous changes to the SAR methodology beginning on page 16 of his direct testimony. Can you summarize his recommendations?

A. Yes, I can. Mr. Schoenbeck's recommended changes to the SAR methodology are fairly extensive and include:

> The SAR method could employ an exogenously determined market price, either hourly or monthly by on and off peak period . . . . (Schoenbeck Direct, p. 16, l. 18.)
>
> Determining four different sets of published prices based on the four different QF delivery patterns applied to the cost stream would recognize the delivery characteristics of each resource type just as Idaho Power is proposing . . . . (Schoenbeck Direct, p. 17, l. 2.)
>
> By requiring annual updates to the gas prices and the corresponding market prices, the SAR method will not be static between integrated resource plan publications. (Schoenbeck Direct, p. 17, l. 7.)

Mr. Schoenbeck goes on to state, "The only item that cannot be directly addressed by these modifications is how additional QFs that commence delivering generation to Idaho Power might impact Idaho's published avoided costs, if at all." (Schoenbeck Direct, p. 17, l. 10).

Q. Do you have any comments regarding Mr. Schoenbeck's recommended changes to the SAR methodology?

A. Yes, but only a general comment. As I read through the recommended changes, it began to sound more like an endorsement of the IRP methodology or the Hourly Incremental Cost methodology proposed by Idaho Power. I am not sure if it would even be feasible to implement the changes Mr. Schoenbeck is recommending to the current SAR model. At the very least, with his recommended changes I think it would be difficult to still consider the SAR model a proxy method for determining avoided cost rates.

V. AVOIDED COST OF CAPACITY

Q. The Staff and the utilities in this case are recommending the avoided cost of capacity be removed from the avoided cost rate until the first deficit year appears in the IRP. Why do you believe this is appropriate?

A. As I have previously stated, utility-owned resources are identified in the IRP based on need and are only constructed or acquired when the need exists. From this standpoint, utilities and QFs would be treated the same as a utility would not be able to place a resource into rates until it was used and useful and a QF would not receive capacity payments until there was an identified need.

Q. On page 14 of his direct testimony, Dr. Reading states "the denial of capacity payments during a period of claimed surplus does not put a QF facility and a company owned generating plant on an equal footing." Do you have any evidence to the contrary?

A. Yes, I do. In the 1980s, Idaho Power faced a surplus capacity situation at the same time that the Company attempted to place the Valmy II generating unit into rate base. The Idaho Public Utilities Commission determined that the Valmy II plant was not used and useful because Idaho Power was in a surplus situation, meaning that in the load and resource balance, resources exceeded load. The exact words of the Commission were:

> We find as a fact that Idaho Power's share of the Valmy II generating plant is not used and useful in the service of its Idaho ratepayers. Power's, Schneider's, and Miller's evidence on this point is overwhelming and uncontroverted. The Company's own load and resources plan demonstrates that Valmy II is surplus capacity until approximately 1993. In the interim, the Company's limited dispatches from Valmy II could be reliably replaced, at a fraction of that plant's fully distributed cost, by generation from Idaho Power's other plants and purchases from the surplus market. (Idaho Public Utilities Commission Case U-I006-265, Order No. 20610, p. 103.)

The final result of this case was that Idaho Power was not allowed a rate of return on this resource until 1989, four years after the resource was constructed and operational.

Q. Beginning on page 9 of his direct testimony, Dr. Reading includes a lengthy discussion of long-run and short-run marginal costs based on the NERA "Grey Books" that were published prior to the passage of PURPA. Specifically on page 12, Dr. Reading states "Unless QFs are credited for long-run capacity costs they will never by [sic] compensated on an equal basis relative to what the utilities receive in rates to build plant." Does the Hourly Incremental Cost methodology proposed by Idaho Power compensate QF developers based on Idaho Power's long-run capacity cost?

A. Yes, the Hourly Incremental Cost methodology compensates QF resources for the capacity they provide based on the estimated long-term cost to add generation capacity to Idaho Power's system. Idaho Power has proposed using the capital costs from an SCCT as the generation resource that determines the capacity credit for QF generation. Using the capital cost from a SCCT insures that a QF resource receives equal treatment to utility-owned resources. In fact, the Hourly Incremental Cost methodology is consistent with the recommendation from the

NERA Grey Books to use the "long-run marginal costs of generating capacity" that Dr. Reading highlights in his testimony.

Dr. Reading argues that QF resources would not be compensated based on long-run marginal costs because they would not receive capacity payments until the first deficit year identified in the IRP. What this is ultimately saying is that QF developers should receive preferential treatment and be compensated for capacity regardless of a utility's need for the capacity.

Compensation for capacity based long-run marginal costs is also impacted by the five-year contract term Idaho Power has proposed. QF developers have rightly argued that it is unrealistic for them to recover the capital cost of their projects in a five-year term. While a utility typically does have generation assets recovered in rates past a five-year period, it is important to point out that PURPA's obligation, and, thus Idaho Power's obligation to contract, lasts past the Company's proposed five-year contract term. Accordingly, as a QF project continues to sign new five-year contracts, it would continue to be compensated for capacity long after a utility-owned resource had been fully depreciated.

Q. On page 31 of his direct testimony, canal company witness Schoenbeck proposes using loss of load analysis results to determine when QF resources should begin being compensated for capacity. Do you agree with this?

A. No, I do not agree for at least two reasons. First, the loss of load expectation analysis Idaho Power performs as part of the IRP is done after a preferred portfolio has been identified and is only done to verify that the selected portfolio provides a reasonable level of assurance that projected loads can be met. Second, a loss of load expectation (or probability) study is complex and difficult to explain to anyone not familiar with the concepts. It would be hard to imagine any of the intervenors in this case that are proponents of simple and transparent processes being supportive of this recommendation.

Q. Mr. Schoenbeck supports his proposal because it produces earlier capacity payments for QF resources, and then goes on to discuss "the game that can be played," by utilities in basing the start of capacity payments on the first deficit month in the IRP load and resource balance. (Schoenbeck Direct, p. 31, l. 13.) To support this statement, Mr. Schoenbeck references Idaho Power's Boardman to Hemingway transmission project and its scheduled on-line date of 2016. Do you agree that Idaho Power was "playing a game" with the scheduled on-line date for the Boardman to Hemingway transmission project?

A. No, I do not. Late in the process of preparing Idaho Power's 2011 IRP, it was determined that delays in permitting were going to cause the scheduled operational date of the project to slip from 2015 to 2016. Therefore, the IRP load and resource balance showed a deficit in 2015, which was eliminated with an "east-side" purchase for the summer months. Idaho Power has relied on short-term purchases from the east side of its system in the past when necessary; however, it is not the preferred choice for market purchases or something the Company wants to rely on long term due to low market liquidity and typically higher prices.

I believe Mr. Schoenbeck's "gaming" concerns could be addressed simply by clarifying how the first deficit year is determined. The way Idaho Power has applied it in the case of the Boardman to Hemingway project mentioned above is based on when the next planned resource is to come on-line. This methodology is based on the utility resource that is potentially being "avoided" due to any new QF resources. The other method that could be used would be to strictly rely on the first deficit year identified in each utility's load and resource balance, which would address Mr. Schoenbeck's concern.

VI. **<u>AVOIDED COST OF ENERGY</u>**

Q. In his direct testimony, Dr. Reading comments on Idaho Power's proposed Hourly Incremental Cost methodology by stating, "the approach incorrectly assumes avoided costs should be based on a *very* short-run hourly basis." (Reading Direct, p. 29, l. 10). Do you agree with Dr. Reading's assessment?

A. No, I do not. Dr. Reading assumes that because the avoided cost of energy is calculated on an hourly basis, the calculation is only focused on the "short-run." The avoided cost of energy calculation in the Hourly Incremental Cost methodology is in fact very "granular" in that every hour for the QF contract term is analyzed. This does not suggest that the methodology is only focused on the "short-run" because the calculation is done for each and every hour throughout the entire contract term.

VII. **<u>CONTRACT TERM</u>**

Q. In his direct testimony, canal company witness Schoenbeck states "The five-year term is unfair and inappropriate because it creates a mismatch between the maximum contract term allowed a QF versus the economic life used or assumed for a comparable utility-owned resource." (Schoenbeck Direct, p. 9, l. 1.) Do you believe this is true?

A. No. What Mr. Schoenbeck does not point out is that a QF resource could simply continue to sign new five-year contracts and ultimately receive capacity payments long after a utility-owned resource was fully depreciated. I believe Mr. Schoenbeck's statement is based on the expectation that the QF would have to pay off any debt associated with the project during the first five-year contract. While I have no firsthand knowledge of whether project financing would become more difficult for QF developers, I do not believe this assumption supports the statement that a five-year contract term is "unfair and inappropriate."

Q. Mr. Schoenbeck goes on to state that "locking into fixed price arrangements reduces Idaho Power's exposure to market price movements." (Schoenbeck Direct, p. 13, l. 13.) Do you agree with this?

A. No. In fact, it has the opposite effect of putting all of the risk on Idaho Power customers and giving the QFs a hedge against potential unfavorable market shifts. History indicates that avoided cost rates exceed market prices and that QFs predominantly insist upon contracts only when contractual prices exceed market rates. See the chart on page 7 of my rebuttal testimony. This chart clearly shows that over the past 10 years Idaho Power has paid substantially more for QF energy compared to market rates. Although it is true in theory that actual prices can go up or down relative to the forecast or contract price, if the price is favorable to the QF, they will insist upon a long-term contract, develop the project, and continue to generate. On the other hand, if the price is not favorable, or no longer favorable, the QF has the options of not contracting, contracting but not developing, or bringing the project on-line, not generating or generating less, or ultimately ceasing operations and walking away from the project and contract. The point being that it is a hedge, or an option that the QF can exercise with customers taking all the downside price risk and hit, and rarely if ever seeing any upside.

Q. Does Staff agree with Idaho Power's views regarding this risk that is shouldered by customers?

A. Yes. Staff witness Sterling also supports this view in his direct testimony regarding fuel price risk.

> Prices established at the start of a long-term contract could prove to be too high or too low compared to other alternatives or to market prices in effect throughout the term of the contract. A long-term contract locks in those prices, regardless of what happens with market prices. Because 100 percent of PURPA costs are passed on to customers through PCAs, ratepayers are fully exposed to the risk that PURPA rates may prove to be too high. (Sterling Direct, p. 30, l. 25.)

I believe what Mr. Sterling states is the exact situation Idaho Power's customers are currently in due to avoided cost rates that have historically been set too high using the SAR methodology.

Q. Staff witness Sterling proposes that a five-year contract term only apply to QF projects larger than the published rate cap. Do you agree with this?

A. While Idaho Power appreciates Staff's agreement that the maximum contract term for all QF contracts under the Hourly Incremental Cost methodology be set at five years, Idaho Power recommends that the five-year contract term apply to all PURPA QF power sale contracts. Staff's recommendation that contracts for all other QF resources under the SAR methodology be entitled to 20-year contracts would only be acceptable to the Company if the published rates based upon the SAR methodology were to remain available only to QFs with a nameplate capacity below 100 kilowatts ("kW"). If the Commission reduces the published rate cap to 100 kW for all QF resource types as the Company has recommended, then most of the risk customers face due to longer-term contracts will be minimized. However, if longer-term contracts are available for published rates for larger QFs up to 10 MW or 10 average megawatts, then all of the problems associated with price risk described above, and by Staff and the Company in direct testimony, will continue to exist, and continue to harm customers.

As stated earlier, the shorter maximum contract term is a safeguard for customers to ensure that the very large risk of locking in prices for the entire duration of the contract is not allowed to continue to inflict substantial financial harm to customers. Because Federal Energy Regulatory Commission ("FERC") regulations allow a QF to unilaterally elect to have the prices in its contract set for the entire duration of the contract based upon price estimates at the time of contracting - as opposed to prices at the time the energy is delivered - the Company, and the Commission, have no means to bring prices back to reality should a large deviation in prices materialize to the detriment of customers, as Idaho Power has demonstrated in its direct testimony in the current case. This is exacerbated by FERC's prohibitions regarding certain price "reopeners" in the QF power sales agreements. Consequently, the only real tool left for the Commission to assure that the Company and its customers are not saddled with substantial long-term harm from price projections that end up deviating substantially from actual prices is to shorten the term of the contract. The obligation to purchase will remain, and the QF can enter into a new contract for the years past year five, or the maximum term of the contract. The Commission and the utility customers can then be assured that even should the price estimates that are established in the contract become harmful and deviate substantially from reality, that they will be looked at anew and refreshed with the new contract, once the maximum term expires.

VIII. <u>PUBLISHED RATE CAP</u>

Q. Canal company witness Schoenbeck recommends setting the published rate cap at 10 MW of nameplate capacity for all resource types (Schoenbeck Direct, p. 14, l. 10). Do you have any concerns regarding this proposal?

A. Yes, I do. Regardless of what avoided cost methodology the Commission decides to use to set rates, published rates could remain stagnant for one to two years. Past experience shows much can change in the energy industry during this time frame, and in order to protect customers from the risk associated with changed conditions, I believe the published rate cap should be set at the minimum FERC required level of 100 kW for all resource types.

As I have proposed previously, if published rates are set using the Hourly Incremental Cost methodology for the various resource types, published rates and negotiated rates for each resource type will remain virtually identical as long as the assumptions made in the IRP remain valid. If any of the assumptions do change, the utilities will be able to update the inputs used in the methodology in order to calculate a current and accurate avoided cost rate. This idea on how to implement and apply published and negotiated rates also has the advantage of no longer needing to rely on the SAR methodology, which I do not believe calculates accurate avoided cost rates.

IX. CARBON ADDER

Q. On page 24 of his direct testimony, canal company witness Schoenbeck advocates for including potential carbon costs in the avoided cost of energy. Witness Looper also discusses the addition of carbon tax costs on page 7 of his direct testimony. Do you agree with their statements?

A. No, I do not. Estimates of future carbon costs are used in the IRP process to evaluate the relative difference between the cost of various resource portfolios. None of these costs are currently real nor are they included in customer rates.

Idaho Power has addressed the carbon adder issue in every IRP it has prepared since at least the 2004 IRP, and used high and low cases for risk analysis purposes. During the IRP cycle, the cost and potential implementation date of a carbon adder are discussed with stakeholders, and today there is just as much uncertainty of these projections as there was in 2004. While appropriate for purposes of evaluating the relative difference between future resource acquisitions in the IRP process, these potential carbon costs do not exist today, and it would be inappropriate to include them in any avoided cost rate.

X. IRP LITIGATION

Q. On page 18 of his direct testimony, Dr. Reading proposes that utility IRPs should "be subject [sic] greater scrutiny and subjected to a litigated hearing and ultimately approval by the Commission." (Reading Direct, p. 18, l. 2.) In leading up to this recommendation, Dr. Reading states, "I would agree if the utilities IRPs were, in fact, subject to significant oversight in their development and submission." (Reading Direct, p. 17, l. 1.) Do you agree with Dr. Reading's opinion concerning the level of oversight in the IRP process?

A. No, I do not. It takes Idaho Power approximately one year to prepare an IRP, and during that time, the Company conducts monthly meetings with the IRP Advisory Council. Members of the council include political, environmental, and customer representatives, Commission Staff representatives, and representatives of other public-interest groups. In addition, the meetings are open to the public and are typically well attended by other stakeholders and interested individuals. The primary purpose of the meetings is to discuss issues related to the IRP and to solicit input on the assumptions that go into the plan.

Following the completion of the IRP and subsequent filing with the Commission, additional public meetings are conducted to present the plan to the public. During this same time, the Commission also solicits public comments.

As the person ultimately responsible for the preparation of Idaho Power's IRP, I can say that there is a significant amount of oversight in the process of preparing the plan.

Q. Are there specific reasons the Commission should not make the IRP a "litigated process"?

A. Yes, there are at least three reasons. First, IRPs are intentionally "accepted" and not "approved" by the Commission so there is no inference of approval of any of the action items contained in the plan. Any new generation resources identified in the plan must still go through a CPCN process, which is fully litigated.

Second, the Commission, utilities, and others recognize that things can change within the two-year period between IRP filings. Having the IRP accepted and not approved provides flexibility for the utilities to react to these changes, without having to go through a protracted legal proceeding.

Finally, as I stated previously, it takes approximately one year to prepare an IRP. The regulatory process as it exists today typically takes an additional six months and shortly after that internal preparations begin for the next IRP. If the IRP were to be fully litigated, I do not believe the two-year cycle would allow time for the Commission to issue an order before the next plan would be underway.

XI. ENVIRONMENTAL ATTRIBUTES

Q. Did Idaho Power make any specific requests of the Commission with regard to Environmental Attributes or RECs of QF generation in its direct testimony in this case?

A. No. In Lisa Grow's direct testimony, Idaho Power acknowledged that RECs were listed by the Commission as one of the issues to be examined in this proceeding in Order No. 32352; however, the Company stated that it had no specific request of the Commission in this regard at the time that direct testimony was filed (January 31, 2012).

Q. Did the Company make any other statements regarding the issue of RECs in its direct testimony?

A. Yes. Witness Grow stated:

> Issues related to PURPA QFs and RECs are currently being litigated by the Company before the Commission in Case No. IPC-E-11-15. The Commission has had proceedings in the past regarding issues related to the ownership of RECs

> between PURPA QFs and the purchasing utility, but the issue of ownership of RECs in the state of Idaho remains an unsettled issue. Idaho Power understands that the Idaho Legislature, which is currently in session, may be considering proposed legislation that would address the ownership of RECs from PURPA QF projects, and thus the Company has no specific request of the Commission in this regard at this time.

Grow Direct, p. 13, l. 22 through p. 14, l. 8.

Q. Has anything changed with regard to the pending Commission cases regarding QF RECs or with the Idaho Legislature since January 31, 2012?

A. Yes, with regard to both. The Idaho Legislature ended its 2012 session without taking any action with regard to the ownership of RECs and utility purchased QF generation. Additionally, the Commission recently issued Order No. 32580 in Case No. IPC-E-11-15 denying a QF's motion for summary judgment regarding its request to require the utility to disclaim ownership of RECs in a QF power purchase agreement.

Q. Does Idaho Power have any specific requests of the Commission with regard to RECs from utility-purchased QF generation at this time?

A. Yes. Idaho Power, similar to other parties to this docket, requests that the Commission specifically find that the Environmental Attributes or RECs from utility purchased QF generation are owned by the purchasing utility.

Q. Have other parties to this docket asked the Commission to make similar findings?

A. Yes. Witness Paul Clements on behalf of Rocky Mountain Power, and witness Rick Sterling on behalf of Commission Staff have recommended that the Commission find that the purchasing utilities should be determined the owners of the RECs from PURPA projects that sell their generation to the utility.

Q. What basis do you have for this recommendation?

A. First of all, Idaho Power agrees with witness Sterling's conclusion that FERC has clearly determined that REC ownership with regard to QF generation is a matter for the states to decide. *Citing*, *American Ref-Fuel Company*, 105 FERC ¶ 61,004 (2003). Additionally, this was confirmed by the Commission in Order No. 32580, Case No. IPC-E-11-15 (June 21, 2012). The Commission in that Order denied a QF's motion for summary judgment requesting that the Commission order the utility to disclaim ownership of the RECs in its QF power purchase agreement. The Commission confirmed that the decision regarding ownership of RECs from QF generation is a decision that lies with the states, and that such a decision has not yet been made in the state of Idaho. The Commission stated, quoting FERC, "States, in creating RECs, have the power to determine who owns the RECs in the initial instance, and how they may be sold or traded; it is not an issue controlled by PURPA." Order No. 32580, p. 5 (citations omitted). The Commission found, "no specific federal or state laws governing the ownership of RECS" and rejected the QF's arguments that other facts supported the QF's contention that it owned the RECs from the PURPA power sale. Order No. 32580, pp. 9-13. The Commission also verifies that its past orders regarding QF REC issues did not address the ownership of those RECs in the initial instance (*Id.*, at pp. 10-11) and that the issue of QF REC ownership in the state of Idaho remains an undecided issue, "Grand View cannot assert a Commerce Clause violation when the ownership of RECs has not been decided." *Id.*, p. 16.

Q. Have any of the QF parties to this docket acknowledged the Commission's authority to decide the issue of QF REC ownership?

A. Yes. Clearwater Paper Corporation, J.R. Simplot Company, and Exergy Development Group of Idaho, LLC, through their witness, Dr. Reading, have asked the Commission to make a decision "as soon as possible" regarding the ownership of environmental attributes. Reading Direct, p. 60. In addition, Grand View Solar II, a party to this case, is the QF referenced above in Order No. 32580 that filed its Complaint asking the Commission to order Idaho Power to disclaim ownership of the RECs in its proposed QF power sales agreement, which the Commission denied.

Q. Does Idaho Power agree with Rocky Mountain Power witness Clements' recommendations that the Commission determine that the utility owns the Environmental Attributes of the QF generation it purchases pursuant to PURPA with no additional compensation beyond what is already paid for the QF generation?

A. Yes. Idaho Power agrees with the position and statements of Rocky Mountain Power in the Direct Testimony of Paul Clements Direct, p. 6, l. 22 through p. 10, l. 13, and by this reference adopts and supports the same.

Q. Does Idaho Power agree with Staff witness Rick Sterling's recommendations to the Commission with regard to the ownership of RECs from utility purchased QF generation?

A. Yes. Idaho Power agrees with witness Sterling's recommendation that the Commission find that the utility owns the RECs from utility purchased QF generation. However, the Company disagrees with his recommendation that the utility be required to pay any amount over the avoided cost rate for rates determined under the SAR avoided cost methodology. The Company, and its customers, in such an instance would be paying twice for what it had all ready purchased from the QF, and paying above the avoided cost.

XII. LIQUIDATED DAMAGES

Q. Several witnesses discuss liquidated damages and the current Commission-approved requirement to post delay damage security with the current PURPA power sales agreements. Does Idaho Power have a position in this regard?

A. Yes. Idaho Power is in favor of and supports the Commission's requirements to post delay damage security with all PURPA power sales agreements in the amount of $45 per kW of nameplate capacity. This has been specifically addressed in numerous Commission cases and numerous different power sales agreements with various QF projects. The Commission has specifically found this requirement to be in the public interest and a just and reasonable requirement of the contracting process. With regard to the reasonableness of liquidated damages, some witnesses, such as Dr. Reading, focus only upon the comparison to the cost of replacement power should the QF not bring its project on-line when it commits itself to a Scheduled Operation Date that it chooses in the contract. This highlights an important part of Idaho Power's case that it provided much evidence of in its direct testimony, and that is typically the Company can acquire replacement power from other available sources at a cost that is below the contract price in the PURPA contract. This, however, is not the only measure of harm and damages. In addition to the system operation and planning problems that failure to bring generation units on-line in a timely manner and when they are scheduled to come on-line, there is the substantial value that the QF gets by locking in a price, and a pricing stream with its contract. If a QF is allowed to come on-line, or not, at its choosing with no consequences and no liability for the value of that option, then customers are left in a financially disadvantaged position and uncompensated for the price lock and option they extended to the QF project. There are financial instruments that can be purchased that would allow a utility to lock in a 20-year, or long-term, stream of prices, and have the option to not execute on that option at a date certain in the future. Such products are very costly, and could be as much as $5 per MWh of power. The $45 per kW of nameplate capacity is very small in comparison, but at least provides an agreed upon valuation of an assessment of risk that the customers are bearing associated with whether a QF generator brings its project on-line when it commits that it will.

XIII. **SCHEDULE 73**

Q. The Company stated in its direct testimony that one of the items it seeks from the Commission is "Establishment of a Commission-authorized negotiation process and procedure by which a PURPA QF can obtain a PPA with Idaho Power." Grow Direct, p. 14. Does Idaho Power have any further details regarding this request?

A. Yes. Upon Idaho Power's review of Rocky Mountain Power's proposed Tariff Schedule 38, provided as Exhibit No. 202 to Rocky Mountain Power witness Clements' testimony, Idaho Power has drafted its proposed Tariff Schedule No. 73, which sets forth a similar process for QFs proposing to contract with Idaho Power. I submit Idaho Power's proposed Tariff Schedule No. 73 as Exhibit No. 10 to this rebuttal testimony. Additionally, submitted as Exhibit No. 11 herewith is a red-lined version of Rocky Mountain Power's proposed Schedule 38, which shows in red-line format the substantive changes between Schedule 38 and Idaho Power's proposed Schedule 73.

Q. Does this conclude your rebuttal testimony in this case?

A. Yes, it does.

BEFORE THE

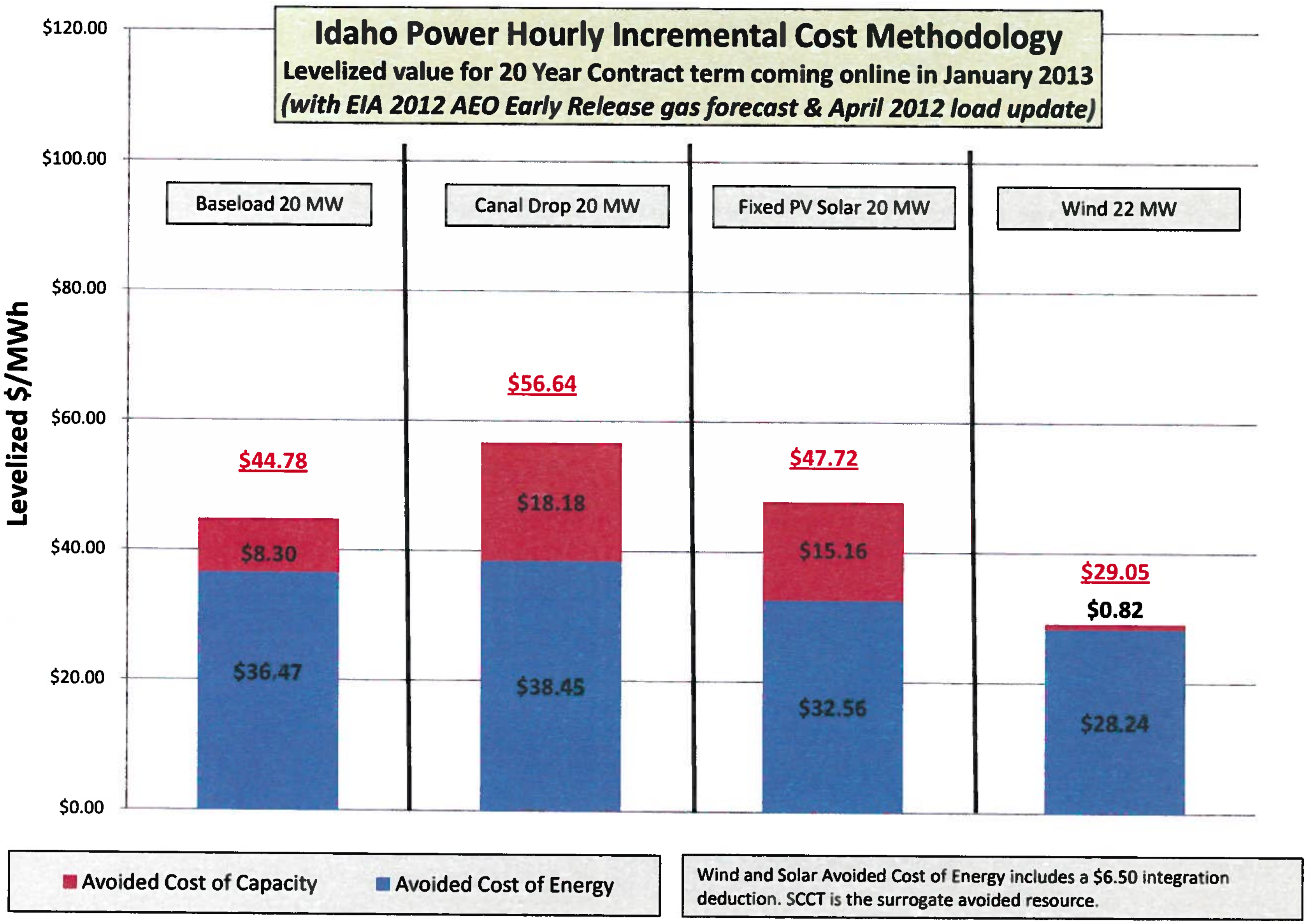
IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. GNR-E-11-03

IDAHO POWER COMPANY

STOKES, REB
TESTIMONY

EXHIBIT NO. 9



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BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. GNR-E-11-03

IDAHO POWER COMPANY

STOKES, REB TESTIMONY

EXHIBIT NO. 10

SCHEDULE 73
ENERGY SALES AGREEMENT PROCEDURES FOR QUALIFYING FACILITIES

AVAILABILITY

Service under this schedule is available to owners of Qualifying Facilities ("QF") throughout the Company's service area within the State of Idaho.

APPLICABILITY

To owners of existing or proposed QFs who desire to make sales to the Company at avoided cost rates. Such owners shall be required to enter into written power purchase and interconnection agreements with the Company pursuant to the procedures set forth in this Schedule 73. Additional or different requirements may apply to Idaho QFs seeking to make sales to third parties or out-of-system QFs seeking to wheel power to Idaho for sale to the Company.

I. PROCESS FOR NEGOTIATING POWER PURCHASE AGREEMENTS

A. Communications

Unless otherwise directed by the Company, all communications to the Company regarding QF power purchase agreements shall be directed in writing as follows:

Idaho Power Company
ATTN: Cogeneration and Small Power Production
1221 West Idaho Street
Boise, Idaho 83702

Any requirement for written notice in this Schedule 73 shall be via mail unless the parties agree by mutual consent to an alternative form. The Company shall respond to all such communications in a timely manner as more fully described below. If the Company is unable to respond on the basis of incomplete or missing information from the QF owner, the Company shall indicate what additional information is required. Thereafter, the Company shall respond in a timely manner following receipt of all required information as more fully described below.

B. Procedures

1. Examples of the Company's typical generic power purchase agreement may be obtained from the Company's web site at www.idahopower.com, or if the owner is unable to obtain it from the web site, the Company shall send a copy via mail within seven calendar days of a written request directed to the address in Part I. A.

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SCHEDULE 73
ENERGY SALES AGREEMENT PROCEDURES
FOR QUALIFYING FACILITIES
(Continued)

I. PROCESS FOR NEGOTIATING POWER PURCHASE AGREEMENTS (Continued)

B. Procedures (Continued)

2. To obtain an indicative pricing proposal with respect to a proposed project, the owner shall provide in writing to the Company, general project information reasonably required for the development of indicative pricing. A project is defined as an existing or proposed QF that desires to make sales to the Company and that can satisfy the requirements of this Schedule 73. General project information shall include, but not be limited to:

a. project name and contact information;
b. generation technology and other related technology applicable to the site;
c. design capacity (MW), station service requirements, and net amount of power to be delivered to the Company's electric system;
d. quantity and timing of hourly power deliveries (estimated hourly generation data for every hour of a one-year period). Upon request, the Company will supply an electronic spreadsheet that can be used by the QF for this purpose;
e. proposed site location and electrical interconnection point;
f. proposed on-line date (date on which deliveries of energy will commence) and outstanding permitting requirements;
g. demonstration of ability to obtain QF status;
h. fuel type(s) and source(s);
i. proposed contract term; and
j. status of interconnection arrangements.

3. The Company shall not be obligated to provide an indicative pricing proposal until all information described in Paragraph 2 has been received in writing from the QF owner. Within 30 calendar days following receipt of all information required in Paragraph 2, the Company shall provide the owner with an indicative pricing proposal, which may include other indicative terms and conditions, tailored to the individual characteristics of the proposed project. Such proposal may be used by the owner to make determinations regarding project planning, financing, and feasibility. However, such prices are merely indicative and are not final and binding. Prices and other terms and conditions are only final and binding to the extent contained in a power purchase agreement executed by both parties and approved by the Commission. Upon request, the Company shall provide with the indicative prices a description of the methodology used to develop the prices.

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SCHEDULE 73
ENERGY SALES AGREEMENT PROCEDURES
FOR QUALIFYING FACILITIES
(Continued)

I. PROCESS FOR NEGOTIATING POWER PURCHASE AGREEMENTS (Continued)

B. Procedures (Continued)

4. If the owner desires to proceed with the project after reviewing the Company's indicative proposal, it shall request in writing that the Company prepare a draft power purchase agreement to serve as the basis for negotiations between the parties. In connection with such request, the owner shall provide the Company with any additional project information that the Company reasonably determines to be necessary for the preparation of a draft power purchase agreement, which may include, but shall not be limited to:

   a. updated information of the categories described in Paragraph B.2;
   b. evidence of adequate control of proposed site;
   c. identification of, and timelines for obtaining any necessary governmental permits, approvals, or authorizations;
   d. assurance of fuel supply or motive force;
   e. anticipated timelines for completion of key project milestones; and
   f. evidence that any necessary interconnection studies have been completed and assurance that the necessary interconnection arrangements are being made in accordance with Part II.

5. The Company shall not be obligated to provide the owner with a draft power purchase agreement until all information required pursuant to Paragraph 4 has been received by the Company in writing. Within 45 calendar days following receipt of all information required pursuant to Paragraph 4, the Company shall provide the owner with a draft power purchase agreement containing a comprehensive set of proposed terms and conditions, including a specific pricing proposal for purchases from the project. Such draft shall serve as the basis for subsequent negotiations between the parties and, unless clearly indicated, shall not be construed as a binding proposal by the Company.

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SCHEDULE 73
ENERGY SALES AGREEMENT PROCEDURES
FOR QUALIFYING FACILITIES
(Continued)

I. PROCESS FOR NEGOTIATING POWER PURCHASE AGREEMENTS (Continued)

B. Procedures (Continued)

6. After reviewing the draft power purchase agreement, the owner shall prepare an initial set of written comments and proposals regarding the draft power purchase agreement and shall provide such comments and proposals, or notice that it has none, to the Company. The Company shall not be obligated to commence negotiations with a QF owner until the Company has received an initial set of written comments and proposals from the QF owner. Following the Company's receipt of such comments and proposals, the owner shall contact the Company to schedule contract negotiations at such times and places as are mutually agreeable to the parties. In connection with such negotiations, the Company:

a. shall not unreasonably delay negotiations and shall respond in good faith to any additions, deletions, or modifications to the draft power purchase agreement that are proposed by the owner;
b. may request to visit the site of the proposed project if such a visit has not previously occurred;
c. shall update its pricing proposals at appropriate intervals to accommodate any changes to the Company's avoided cost calculations, the proposed project, or proposed terms of the draft power purchase agreement;
d. may request any additional information from the owner necessary to finalize the terms of the power purchase agreement and satisfy the Company's due diligence with respect to the project; and
e. shall resolve disputes related to power purchase agreement terms consistent with Part III of this Schedule 73.

7. When both parties are in full agreement as to all terms and conditions of the draft power purchase agreement, the Company shall prepare and forward to the owner within 45 calendar days a final, executable version of the agreement. The Company reserves the right to condition execution of the power purchase agreement upon simultaneous execution of an interconnection agreement between the owner and the Company's power delivery function, as discussed in Part II. Prices and other terms and conditions in the power purchase agreement shall not be final and binding until the power purchase agreement has been executed by both parties and the Commission approves the agreement.

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SCHEDULE 73
ENERGY SALES AGREEMENT PROCEDURES
FOR QUALIFYING FACILITIES
(Continued)

II. PROCESS FOR INTERCONNECTION

In addition to negotiating a power purchase agreement, QFs intending to make sales to the Company are also required to enter into a Generator Interconnection Agreement ("GIA") pursuant to the Company's Schedule 72 – Interconnections to Non-Utility Generation and be designated as a network resource to serve Idaho Power's system load. The Company's obligation to make purchases from a QF is conditioned upon the consummation of all necessary interconnection arrangements.

It is recommended that the owner initiate its request for interconnection as early in the planning process as possible, to ensure that necessary interconnection arrangements proceed in a timely manner on a parallel track with negotiation of the power purchase agreement.

Because of functional separation requirements mandated by the Federal Energy Regulatory Commission, interconnection and power purchase agreements are handled by different functions within the Company. Interconnection agreements (both transmission and distribution level voltages) are handled by the Company's power delivery function.

A. Communications

Initial communications regarding the interconnection process should be directed to the Company in writing as follows:

Idaho Power Company
ATTN: Load-Serving Operation
1221 West Idaho Street
Boise, Idaho 83702

B. Procedures

The required procedures for QF interconnection to Idaho Power's system are set forth in the Company's Schedule 72 – Interconnections to Non-Utility Generation. Generally, the interconnection process involves (1) initiating a request for interconnection, (2) completion of studies to determine the system impacts associated with the interconnection and the design, cost, and schedules for constructing any necessary interconnection facilities, and (3) execution of a GIA.

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SCHEDULE 73
ENERGY SALES AGREEMENT PROCEDURES
FOR QUALIFYING FACILITIES
(Continued)

III. PROCESS FOR FILING A COMPLAINT WITH THE COMMISSION ON CONTRACT TERMS

Before filing a complaint with the Idaho Public Utilities Commission on any specific power purchase agreement term not agreed upon between the counterparty and the Company, a counterparty must wait 60 calendar days from the date it notifies the Company in writing that it cannot reach agreement on a specific term. This includes but is not limited to any disputes that are not resolved through the procedures set forth in Part I. B. 6.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. GNR-E-11-03

IDAHO POWER COMPANY

STOKES, REB TESTIMONY

EXHIBIT NO. 11

ROCKY MOUNTAIN POWER

ELECTRIC SERVICE SCHEDULE NO. 38

STATE OF IDAHO

Avoided Cost Purchases from Non-Standard Qualifying Facilities

Availabilitye
Service under this schedule is available t~~T~~o owners of Qualifying Facilities ("QF") ~~in all territory served by the Company in~~throughout the Company's Service Area within the State of Idaho.

Applicabilitye
To owners of existing or proposed QFs who desire to make sales to the Company at Avoided Cost Rates~~and who: (1) have a design capacity greater than 1,000 kW and a historic or projected annual capacity factor of seventy percent or below, or (2) have an average monthly capacity and associated energy of greater than 10,000 kW and a historic or projected annual capacity factor of greater than seventy percent~~. Such owners shall be required to enter into written power purchase and interconnection agreements with the Company pursuant to the procedures set forth ~~below~~in this Schedule 73. Additional or different requirements may apply to Idaho QFs seeking to make sales to third-parties or out-of-system QFs seeking to wheel power to Idaho for sale to the Company.

I. Process For Negotiating Power Purchase Agreements

A. Communications
Unless otherwise directed by the Company, all communications to the Company regarding QF power purchase agreements shall be directed in writing, by mail, as follows:

~~Rocky Mountain Power~~Idaho Power Company
~~Manager – QF Contracts~~ATTN: Cogeneration and Small Power Production
~~825 NE Multnomah St, Suite 600~~1221 West Idaho Street
~~Portland, Oregon 97232~~Boise, Idaho 83702

Any requirement for written notice in this tariff shall be via mail unless the parties agree by mutual consent to an alternative form. The Company shall respond to all such communications in a timely manner as more fully described below.

(Continued)

ELECTRIC SERVICE SCHEDULE NO. 38 - Continued

I. A. Communications (continued)

If the Company is unable to respond on the basis of incomplete or missing information from the QF owner, the Company shall indicate what additional information is required. Thereafter, the Company shall respond in a timely manner following receipt of all required information as more fully described below.

B. Procedures

1. Examples of the Company's typical generic power purchase agreement may be obtained from the Company's website at ~~www.pacificorp.com~~www.idahopower.com, or if the owner is unable to obtain it from the website, the Company shall send a copy via mail within seven calendar days of a written request directed to the address in Part I. A.

2. To obtain an indicative pricing proposal with respect to a proposed Project, the owner shall provide in writing to the Company, general project information reasonably required for the development of indicative pricing. A Project is defined as an existing or proposed QF that desires to make sales to the Company and that can satisfy the requirements of Schedule 38. General project information shall include, but not be limited to:

a) Project name and contact information;
~~a)~~b) generation technology and other related technology applicable to the site;
~~b)~~c) design capacity (MW), station service requirements, and net amount of power to be delivered to the Company's electric system;
~~c)~~d) quantity and timing of ~~monthly~~ hourly power deliveries (~~including Project ability to respond to dispatch orders from the Company~~estimated hourly generation data for every hour of a one-year period). Upon request, the Company will supply an electronic spreadsheet that can be used by the QF for this purpose;
~~d)~~e) proposed site location and electrical interconnection point;
~~e)~~f) proposed on-line date (date on which deliveries of energy will commence) and outstanding permitting requirements;
~~f)~~g) demonstration of ability to obtain QF status;
~~g)~~h) fuel type(s) and source(s);
~~h) plans for fuel and transportation agreements, including plans for what party or parties will pay transmission costs;~~

i) proposed contract ~~term and pricing provisions (i.e., fixed, escalating, indexed)~~; and,
j) status of interconnection arrangements.

(Continued)

ELECTRIC SERVICE SCHEDULE NO. 38 - Continued

I. B. Procedures (continued)

3. The Company shall not be obligated to provide an indicative pricing proposal until all information described in Paragraph 2 has been received in writing from the QF owner. Within 30 calendar days following receipt of all information required in Paragraph 2, the Company shall provide the owner with an indicative pricing proposal, which may include other indicative terms and conditions, tailored to the individual characteristics of the proposed Project. Such proposal may be used by the owner to make determinations regarding Project planning, financing and feasibility. However, such prices are merely indicative and are not final and binding. Prices and other terms and conditions are only final and binding to the extent contained in a power purchase agreement executed by both parties and ~~accepted for filing~~approved by the Idaho Public Utilities Commission. Upon request, the Company shall provide with the indicative prices a description of the methodology used to develop the prices.

4. If the owner desires to proceed with the Project after reviewing the Company's indicative proposal, it shall request in writing that the Company prepare a draft power purchase agreement to serve as the basis for negotiations between the parties. In connection with such request, the owner shall provide the Company with any additional Project information that the Company reasonably determines to be necessary for the preparation of a draft power purchase agreement, which may include, but shall not be limited to:

   a) updated information of the categories described in Paragraph B.2;
   b) evidence of adequate control of proposed site;
   c) identification of, and timelines for obtaining any necessary governmental permits, approvals or authorizations;
   d) assurance of fuel supply or motive force;
   e) anticipated timelines for completion of key Project milestones; and,
   f) evidence that any necessary interconnection studies have been completed and assurance that the necessary interconnection arrangements are being made in accordance with Part II.

(Continued)

ELECTRIC SERVICE SCHEDULE NO. 38 - Continued

I. B. Procedures (continued)

5. The Company shall not be obligated to provide the owner with a draft power purchase agreement until all information required pursuant to Paragraph 4 has been received by the Company in writing. Within 45 calendar days following receipt of all information required pursuant to Paragraph 4, the Company shall provide the owner with a draft power purchase agreement containing a comprehensive set of proposed terms and conditions, including a specific pricing proposal for purchases from the Project. Such draft shall serve as the basis for subsequent negotiations between the parties and, unless clearly indicated, shall not be construed as a binding proposal by the Company.

6. After reviewing the draft power purchase agreement, the owner shall prepare an initial set of written comments and proposals regarding the draft power purchase agreement and shall provide such comments and proposals, or notice that it has none, to the Company. The Company shall not be obligated to commence negotiations with a QF owner until the Company has received an initial set of written comments and proposals from the QF owner. Following the Company's receipt of such comments and proposals, the owner shall contact the Company to schedule contract negotiations at such times and places as are mutually agreeable to the parties. In connection with such negotiations, the Company:

   a) shall not unreasonably delay negotiations and shall respond in good faith to any additions, deletions or modifications to the draft power purchase agreement that are proposed by the owner;
   b) may request to visit the site of the proposed Project if such a visit has not previously occurred;
   c) shall update its pricing proposals at appropriate intervals to accommodate any changes to the Company's avoided-cost calculations, the proposed Project or proposed terms of the draft power purchase agreement;
   d) may request any additional information from the owner necessary to finalize the terms of the power purchase agreement and satisfy the Company's due diligence with respect to the Project; and,
   e) shall resolve disputes related to power purchase agreement terms consistent with Part III of this tariff.

(Continued)

ELECTRIC SERVICE SCHEDULE NO. 38 - Continued

I. B. **Procedures (continued)**

7. When both parties are in full agreement as to all terms and conditions of the draft power purchase agreement, the Company shall prepare and forward to the owner within 45 calendar days a final, executable version of the agreement. The Company reserves the right to condition execution of the power purchase agreement upon simultaneous execution of an interconnection agreement between the owner and the Company's power delivery function, as discussed in Part II. Prices and other terms and conditions in the power purchase agreement shall not be final and binding until the power purchase agreement has been executed by both parties and the Idaho Public Utilities Commission ~~accepts~~ approves the agreement ~~for filing~~.

II. Process for Negotiating Interconnection Agreements

In addition to negotiating a power purchase agreement, QFs intending to make sales to the Company are also required to enter into a~~n~~ Generator ~~I~~Interconnection A~~a~~greement ("GIA") pursuant to the Company's Schedule 72 – Interconnections to Non-Utility Generation and be designated as a network resource to serve Idaho Power's system load ~~that governs the physical interconnection of the Project to the Company's transmission or distribution system~~. The Company's obligation to make purchases from a QF is conditioned upon the consummation of all necessary interconnection arrangements.

It is recommended that the owner initiate its request for interconnection as early in the planning process as possible, to ensure that necessary interconnection arrangements proceed in a timely manner on a parallel track with negotiation of the power purchase agreement.

Because of functional separation requirements mandated by the Federal Energy Regulatory Commission, interconnection and power purchase agreements are handled by different functions within the Company. Interconnection agreements (both transmission and distribution level voltages) are handled by the Company's power delivery function.

(Continued)

ELECTRIC SERVICE SCHEDULE NO. 38 - Continued

II. A. Communications

Initial communications regarding the interconnection ~~agreements~~ process should be directed to the Company in writing as follows:

~~PacifiCorp Transmission~~Idaho Power Company
~~Transmission Account Management~~ATTN: Load-Serving Operation
~~825 NE Multnomah St, Suite 1600~~1221 West Idaho Street
~~Portland, Oregon 97232~~Boise, Idaho 83702

~~Based on the Project size and other characteristics, the Company shall direct the QF owner to the appropriate individual within the Company's power delivery function responsible for negotiating the interconnection agreement with the QF owner. Thereafter, the QF owner should direct all communications regarding interconnection agreements to the designated individual, with a copy of any written communications to the address set forth above.~~

B. Procedures

The required procedures for QF interconnection to Idaho Power's system are set forth in the Company's Schedule 72 – Interconnections to Non-Utility Generation. Generally, the interconnection process involves (1) initiating a request for interconnection, (2) completion of studies to determine the system impacts associated with the interconnection and the design, cost, and schedules for constructing any necessary interconnection facilities, and (3) execution of ~~an~~ GIA ~~Interconnection Facilities Agreement to address facility construction, testing and acceptance, and (4) execution of an Interconnection Operation and Maintenance Agreement to address ownership and operation and maintenance issues~~.

~~For interconnections impacting the Company's Transmission System, the Company shall process the interconnection application through PacifiCorp Transmission Services following the procedures for studying the generation interconnection described in the latest version of the Company's Open Access Transmission Tariff, PacifiCorp FERC Electric Tariff, Volume No. 11 Pro Forma Open Access Transmission Tariff (OATT) on file with the Federal Energy Regulatory Commission. A copy of the OATT is available on-line at: http//www.oasis.pacificorp.com~~

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

~~For interconnections impacting the Company's Distribution System only, the Company will process the interconnection application through the Manager – QF Contracts at the address shown in Part I. A.~~

(Continued)

ELECTRIC SERVICE SCHEDULE NO. 38 - Continued

III. Process for Filing a Complaint with the Commission on Contract Terms

Before filing a complaint with the Idaho Public Utilities Commission on any specific power purchase agreement term not agreed upon between the counterparty and the Company, a counterparty must wait 60 calendar days from the date it notifies the Company in writing that it cannot reach agreement on a specific term. This includes but is not limited to any disputes that are not resolved through the procedures set forth in Part I. B. 6.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on the 29th day of June 2012 I served a true and correct copy of the REBUTTAL TESTIMONY OF M. MARK STOKES upon the following named parties by the method indicated below:

Commission Staff Donald L. Howell, II Kristine A. Sasser Deputy Attorneys General Idaho Public Utilities Commission 472 West Washington (83702) P.O. Box 83720 Boise, Idaho 83720-0074	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FAX _X_ Email don.howell@puc.idaho.gov kris.sasser@puc.idaho.gov
Avista Corporation Michael G. Andrea Avista Corporation 1411 East Mission Avenue, MSC-23 P.O. Box 3727 Spokane, Washington 99220-3727	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FAX _X_ Email michael.andrea@avistacorp.com
PacifiCorp d/b/a Rocky Mountain Power Daniel E. Solander PacifiCorp d/b/a Rocky Mountain Power 201 South Main Street, Suite 2300 Salt Lake City, Utah 84111	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FAX _X_ Email daniel.solander@pacificorp.com
Exergy Development, Grand View Solar II, J.R. Simplot, Northwest and Intermountain Power Producers Coalition, Board of Commissioners of Adams County, Idaho, and Clearwater Paper Corporation Peter J. Richardson Gregory M. Adams RICHARDSON & O'LEARY, PLLC 515 North 27th Street (83702) P.O. Box 7218 Boise, Idaho 83707	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FAX _X_ Email peter@richardsonandoleary.com greg@richardsonandoleary.com
Exergy Development Group of Idaho, LLC James Carkulis, Managing Member Exergy Development Group of Idaho, LLC 802 West Bannock Street, Suite 1200 Boise, Idaho 83702	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FAX _X_ Email jcarkulis@exergydevelopment.com

Dr. Don Reading Ben Johnson Associates, Inc. 6070 Hill Road Boise, Idaho 83703	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FAX _X_ Email dr@benjohnsonassociates.com
Grand View Solar II Robert A. Paul Grand View Solar II 15690 Vista Circle Desert Hot Springs, California 92241	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FAX _X_ Email robertapaul08@gmail.com
J.R. Simplot Company Don Sturtevant, Energy Director J.R. Simplot Company One Capital Center 999 Main Street P.O. Box 27 Boise, Idaho 83707-0027	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FAX _X_ Email don.sturtevant@simplot.com
Northwest and Intermountain Power Producers Coalition Robert D. Kahn, Executive Director Northwest and Intermountain Power Producers Coalition 1117 Minor Avenue, Suite 300 Seattle, Washington 98101	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FAX _X_ Email rkahn@nippc.org
Board of Commissioners of Adams County, Idaho Bill Brown, Chair Board of Commissioners of Adams County, Idaho P.O. Box 48 Council, Idaho 83612	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FAX _X_ Email bdbrown@frontiernet.net
Clearwater Paper Corporation Marv Lewallen Clearwater Paper Corporation 601 West Riverside Avenue, Suite 1100 Spokane, Washington 99201	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FAX _X_ Email marv.lewallen@clearwaterpaper.com
Renewable Energy Coalition and Dynamis Energy, LLC Ronald L. Williams WILLIAMS BRADBURY, P.C. 1015 West Hays Street Boise, Idaho 83702	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FAX _X_ Email ron@williamsbradbury.com

Renewable Energy Coalition John R. Lowe, Consultant Renewable Energy Coalition 12050 SW Tremont Street Portland, Oregon 97225	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FAX _X_ Email jravenesanmarcos@yahoo.com
Dynamis Energy, LLC Wade Thomas, General Counsel Dynamis Energy, LLC 776 East Riverside Drive, Suite 150 Eagle, Idaho 83616	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FAX _X_ Email wthomas@dynamisenergy.com
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Bill Piske, Manager Interconnect Solar Development, LLC 1303 East Carter Boise, Idaho 83706	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FAX _X_ Email billpiske@cableone.net
Renewable Northwest Project, Idaho Windfarms, LLC, and Ridgeline Energy LLC Dean J. Miller Chas. F. McDevitt McDEVITT & MILLER LLP 420 West Bannock Street (83702) P.O. Box 2564 Boise, Idaho 83701	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FAX _X_ Email joe@mcdevitt-miller.com chas@mcdevitt-miller.com
Megan Walseth Decker Senior Staff Counsel Renewable Northwest Project 421 SW 6th Avenue, Suite 1125 Portland, Oregon 97204	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FAX _X_ Email megan@rnp.org
Idaho Windfarms, LLC Glenn Ikemoto Margaret Rueger Idaho Windfarms, LLC 672 Blair Avenue Piedmont, California 94611	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FAX _X_ Email glenni@envisionwind.com margaret@envisionwind.com

Twin Falls Canal Company and North Side Canal Company
C. Thomas Arkoosh
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Donald W. Schoenbeck
RCS, Inc.
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Vancouver, Washington 98660

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____Overnight Mail
____FAX
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Twin Falls Canal Company
Brian Olmstead, General Manager
Twin Falls Canal Company
P.O. Box 326
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ELECTRONIC SERVICE ONLY
North Side Canal Company
Ted Diehl, General Manager
North Side Canal Company
921 North Lincoln Street
Jerome, Idaho 83338

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Ted S. Sorenson, P.E.
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Snake River Alliance Liz Woodruff, Executive Director Ken Miller, Clean Energy Program Director Snake River Alliance 350 North 9th Street #B610 P.O. Box 1731 Boise, Idaho 83701	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FAX _X_ Email lwoodruff@snakeriveralliance.org kmiller@snakeriveralliance.org
Energy Integrity Project Tauna Christensen Energy Integrity Project 769 North 1100 East Shelley, Idaho 83274	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FAX _X_ Email tauna@energyintegrityproject.org
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Christa Bearry

Christa Bearry, Legal Assistant