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May 21, 2013

VIA ELECTRONIC AND U.S. MAIL

PUC Filing Center
Public Utility Commission of Oregon
PO Box 2148
Salem, OR 97308-2148

Re: UM 1610 – In the Matter of OREGON PUBLIC UTILITY COMMISSION, Investigation into Qualifying Facility Contracting and Pricing

Attention Filing Center:

Enclosed for filing in docket UM 1610 are an original and two copies of Idaho Power Company's Cross Exhibit List and the corresponding Cross Examination Exhibits.

A copy of this filing has been served on all parties to this proceeding as indicated on the attached certificate of service.

Please contact this office with any questions.

Very truly yours,

Wendy McIndoo

Wendy McIndoo
Office Manager

Enclosures

cc: Service List

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UM 1610

In the Matter of PUBLIC UTILITY COMMISSION OF OREGON Investigation into Qualifying Facility Contracting and Pricing.	**IDAHO POWER COMPANY'S CROSS EXAMINATION EXHIBITS AND EXHIBIT LIST**

Pursuant to the May 13, 2013, Prehearing Conference Memorandum issued by Administrative Law Judges ("ALJ") Shani Pines and Traci A.G. Kirkpatrick, Idaho Power Company ("Idaho Power" or "Company") submits the following exhibit list and cross examination exhibits. As described in Idaho Power Company's Amended Cross Examination Statement, filed on May 20, 2013, and Second Amended Cross Examination Statement, filed on May 21, 2013, Idaho Power has agreed to waive cross examination in exchange for the entry into the record of this proceeding of the following exhibits, which accompany this filing:

1. Idaho Power/500: Staff Exhibit 100, the Reply Testimony of Philip Carver, filed in Docket UM 1559 on June 7, 2012.
2. Idaho Power/501: Staff Exhibit 300, the Surrebuttal Testimony of Philip Carver, filed in Docket UM 1559 on July 19, 2012.
3. Idaho Power/502: Testimony of Dr. Don Reading before the Idaho Public Utilities Commission in Case No. GNR-E-11-03.

In addition to these cross examination exhibits, Idaho Power also intends to move into the record the following pre-filed testimony and exhibits:

1. Idaho Power/100, Direct Testimony of Lisa A. Grow, dated February 4, 2013.

McDowell Rackner & Gibson PC
419 SW Eleventh Avenue, Suite 400
Portland, OR 97205

2. Idaho Power/101, Exhibit Accompanying Direct Testimony of Lisa A. Grow (QF Development on Idaho Power's System).
3. Idaho Power/200, Direct Testimony of M. Mark Stokes, dated February 4, 2013.
4. Idaho Power/201, Exhibit Accompanying Direct Testimony of M. Mark Stokes (Idaho Power PURPA QF Project List as of December 31, 2012).
5. Idaho Power/202, Exhibit Accompanying Direct Testimony of M. Mark Stokes (Idaho Power PURPA Expense—Historical and Forecast).
6. Idaho Power/203, Exhibit Accompanying Direct Testimony of M. Mark Stokes (Idaho Power's Proposed Oregon Method).
7. Idaho Power/204, Exhibit Accompanying Direct Testimony of M. Mark Stokes (Idaho Power's Incremental Cost IRP Methodology).
8. Idaho Power/205, Exhibit Accompanying Direct Testimony of M. Mark Stokes (Wind Integration Study).
9. Idaho Power/300, Additional Direct Testimony of M. Mark Stokes, dated February 19, 2013.
10. Idaho Power/301, Exhibit Accompanying Additional Direct Testimony of M. Mark Stokes (Current Oregon Standard Agreement (Intermittent Resource)).
11. Idaho Power/302, Exhibit Accompanying Additional Direct Testimony of M. Mark Stokes (Current Oregon Standard Agreement (Non-Intermittent Resource)).
12. Idaho Power/303, Exhibit Accompanying Additional Direct Testimony of M. Mark Stokes (Idaho Standard Agreement (Intermittent Resource)).
13. Idaho Power/304, Exhibit Accompanying Additional Direct Testimony of M. Mark Stokes (Idaho Standard Agreement (Non-Intermittent Resource)).
14. Idaho Power/400, Reply Testimony of M. Mark Stokes, dated April 29, 2013.

Dated: May 21, 2013.

MCDOWELL RACKNER & GIBSON PC

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CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing document in Docket UM 1610 the following named person(s) on the date indicated below by email addressed to said person(s) at his or her last-known address(es) indicated below.

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DATED: May 21, 2013

Wendy McIndoo

Wendy McIndoo
Office Manager

PUBLIC UTILITY COMMISSION OF OREGON

UM 1559

STAFF REPLY TESTIMONY OF

PHILIP CARVER

In the Matter of
PUBLIC UTILITY COMMISSION OF OREGON
Investigation into the Appropriate Calculation of Resource Value for Solar Photovoltaic (PV)

June 7, 2012

CASE: UM 1559
WITNESS: Philip Carver

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 100

Reply Testimony

June 7, 2012

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Philip H. Carver. I am a Senior Policy Analyst in the Electric Rates and Planning Section of the Oregon PUC. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/101.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony will discuss the types of analyses that I recommend the three electric companies submit to establish resource value.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

Issue 1: Purpose of this docket

Issue 2: Assessment of the three company fillings

Issue 3: Concepts for the resource value of solar power

Issue 4: Information parties should file on June 28

Issue 1: PURPOSE OF THIS DOCKET

Q: WHAT IS THE PURPOSE OF THIS DOCKET?

A. The Commission opened this docket to investigate the appropriate methods to calculate the resource value of solar photovoltaic systems enrolled in the Solar Photovoltaic Pilot Program ("SPV Pilot"). The three electric companies are required by rule to file estimates of the 15-year levelized resource value for SPV power (from the SPV Pilots) on November 1, 2010, 2012, and 2014. (OAR 860-084-0370(1).) All three companies made their filings on November 1, 2010, but did not use consistent methods to estimate resource value. This docket is to investigate whether the Commission should issue specific criteria for the November 1, 2012 filing to ensure consistency among the companies.

Q. WHAT IS THE RESOURCE VALUE?

A. "Resource value" is defined at ORS 757.360 as follows:

"Resource value" means the estimated value to an electric company of the electricity delivered from a solar photovoltaic energy system associated with:

(a) The avoided cost of energy, including avoided fuel price volatility, minus the costs of firming and shaping the electricity generated from the facility; and

(b) Avoided distribution and transmission cost.

Q. WHAT IS THE PURPOSE OF ESTABLISHING THE RESOURCE VALUE OF THE SPV SYSTEMS ENROLLED IN THE SPV PILOT?

A. When adopting the legislation establishing the SPV Pilot, the legislature specified that at the end of the 15-year SVP Pilot, participants are eligible to receive payments for energy generated on their systems at a rate equal to the resource value. *See* ORS 757.365(4). Also, ORS 757.365(9) provides that to the extent rates paid under a pilot program exceed the resource value, SPV Pilot participants are not eligible for expenditures under ORS 757.612 (from the public purpose charge) or for tax credits under ORS 469B.100 to 469B.118 or 469B.130 to 469B.169). Finally, as Staff noted in its request to the Commission to open this docket, the information may be useful in evaluating the effectiveness of the SPV Pilot for the Commission's report to the Legislature on January 1, 2013.

Q. SHOULD THIS DOCKET ADDRESS SOLAR RESOURCE VALUE ESTIMATES THAT WILL BE FILED BEGINNING JANUARY 1, 2025 UNDER OAR 860-84-0370(2)?

A. No. This is not the appropriate docket to address methodological or empirical questions related to solar resource value in 2025 and beyond. Too much will change in the next twelve years for any technical or numerical judgments by this Commission to be of much use to the Commission in 2025.

<u>ISSUE 2: ASSESSMENT OF THE VALUE OF UTILITY FILLINGS</u>

Q. ARE THE FILINGS MADE BY PGE AND PACIFICORP IN THIS DOCKET USEFUL TO ESTABLISH THE SPV RESOURCE VALUE?

A. No. Both companies based their estimates of resource value on their interpretation of the recently-ordered Commission methodology for determining renewable avoided cost prices under the Public Utility Regulatory Policy Act (PURPA) (16 U.S.C. § 824 *et seq*.) (Joint Testimony/100, Brown-Macfarlane/2.) The Commission issued an order establishing this methodology in Docket No. UM 1396. (Order No. 11-505).

However, as discussed in more detail below, estimates of solar resource value are distinct from the avoided cost concept under the federal PURPA statute, and relying on the Commission's avoided cost methodology to establish resource value is not sufficient.

Second, the renewable avoided cost cannot be the basis for the solar resource value under ORS 757.360(5). The renewable avoided cost is inherently based on the value of the renewable energy certificate (REC) to the company for compliance the renewable portfolio standard under ORS 469A.130. Yet, the Legislature explicitly removed RECs from the definition of solar resource value in HB 3690 (2010 session).

Third, whether PGE and PacifiCorp correctly interpreted the Commission's UM 1396 order regarding the methodology to determine renewable avoided cost prices is yet to be determined and may not be determined in time to be relevant in this docket. Testimony in this docket will conclude on July 19. That deadline cannot be delayed much, if at all. The three companies will submit the reports required under OAR 860-84-0370(3) on Nov. 1. For a Commission order in this docket to inform the Nov. 1 reports, it will need to be issued around or before Oct. 1. The proceedings under UM 1396 and follow-on dockets will surely not be completed by July 19. There has not even been a pre-hearing conference. Therefore, the UM 1396 filings will not be adjudicated in time to be useful in this docket. Furthermore, Commission staff cannot respond to testimony in UM 1396 in this docket. Staff must respond in the appropriate docket at the appropriate time.

Q. WHY IS THERE A DISTINCTION BETWEEN PURPA AVOIDED COSTS AND RESOURCE VALUE?

A. First, even though the statutory definition includes “[t]he avoided cost of energy,” it also includes “avoided fuel price volatility.” The value of avoiding fuel price volatility goes beyond the PURPA definition of “avoided costs.” To get a fair measure of value the Commission should consider other elements beyond PURPA avoided costs. Opportunity cost is one value the Commission should include in solar resource value.

Q. WHAT ARE OPPORTUNITY COSTS?

Wikipedia defines opportunity cost as “the cost of any activity measured in terms of the value of the next best alternative forgone (that is not chosen).” In this case the opportunity cost of not having power from the SPV Pilot is the value of extra wholesale sales that the electric company cannot make or purchases that it need not make.

Q. PLEASE ASSESS THE USEFULNESS OF THE TESTIMONY FILED BY THE IDAHO POWER COMPANY (IPC) ON MAY 10 IN THIS CONTEXT.

A. Like PacifiCorp and PGE, IPC uses a methodology for determining avoided cost prices under PURPA that has not been approved by the Oregon Commission, and that will likely be addressed in a generic docket. (Idaho Power/100, Allphin/7.) Requiring parties to comment regarding the validity of IPC's "IRP Method" of calculating PURPA avoided costs in this docket unnecessarily complicates this docket. In any event, IPC excludes any capacity credit for solar and assumes no reductions in line losses, which staff believes is inappropriate. (Idaho Power/100, Allphin/7-8, 11.)

IPC's justification for excluding savings from decreased line losses as "so minimal" is unpersuasive. (*See* Idaho Power/100, Allphin/11.) Compared to the total system costs for any of the three companies, the resource savings from their proportional share of the 25 nameplate MW of solar in this program are minimal. Unlike reductions in distribution investments or solar integration costs, there are no threshold issues for reduction in line losses. Loss reductions occur automatically when loads are reduced. PGE and PacifiCorp include line loss estimates. (*See* Joint Testimony101, Brown-Macfarlane/(1,Joint Testimony/102, Brown-Macfarlane/3.) IPC has no differentiating characteristic, as compared with PGE and PacifiCorp, that justifies exclusion of IPC line losses from the value of distributed solar power.

IPC's testimony that it did not include the cost of avoided capacity in its estimate of resource value because the statutory definition does not specifically refer to avoided cost of capacity is also not persuasive. (Idaho Power/100, Allphin/7-8.) As noted above, the legislature directed the Commission to determine the **value** to electric companies of the solar PV power. Staff does not think it is appropriate, for purposes of these preliminary resource value estimates, to exclude an element of the value based on a narrow interpretation of ORS 757.360(5).

Q. HOW WOULD YOU COMPARE IPC'S PRELIMINARY ESTIMATE OF SOLAR RESOURCE VALUE WITH THE ESTIMATE IPC FILED ON NOV. 1, 2010?

A. For at least one element, I liked the 2010 filing better. Consistent with the concept of opportunity cost, IPC used Mid-Columbia high-load hour wholesale prices from its 2009 integrated resource plan (IRP). Using the levelized 15 years of power prices is consistent with the opportunity cost approach to solar resource value. In both cases IPC included zero values for capacity credit and line losses, which I discussed in the previous answer.

ISSUE 3: CONCEPTS FOR THE RESOURCE VALUE OF SOLAR POWER

Q. WHAT ARE THE CONCEPTS RELATED TO THE RESOURCE VALUE OF THE SOLAR POWER THAT COMPANIES SHOULD INCLUDE IN THEIR FILINGS ON NOV. 1?

A. At this time Staff finds that companies should be able to report on the following elements of solar resource value from the pilot program:

1. The value of the energy;
2. The value of capacity no longer needed, but for the solar power;
3. The incremental reductions of transmission and distribution (T&D) losses;
4. The value of avoided fuel price volatility;
5. The cost to the company to firm and shape the solar PV power, if any;
6. Long-run avoidable transmission and distribution (T&D) costs (other than losses) and net incremental T&D costs, if any.

Q. HOW SHOULD THE COMPANIES ESTIMATE THE VALUE OF THE ENERGY?

A. The companies should use forecasts of wholesale power prices for the 20 year period of the SPV contracts (2010 to 2030), differentiated by time-of-day (low-load hours vs. high-load hours) and month (weighted by solar output) from their most recently acknowledged IRP with base case or average regulatory carbon assumptions.

Wholesale power prices represent the opportunity cost of power that is available for sale (or that reduces company wholesale purchases) due to the reductions in net load from the solar power. While estimates of the regulatory carbon adder are uncertain, so are many other elements used to forecast wholesale power prices.

The Clean Air Act mandates that the U.S. Environmental Protection Agency regulate carbon emissions. Actions by EPA and other federal agencies will, in all likelihood, raise wholesale power prices substantially. An implicit carbon adder incorporates these likely costs.

Q. HOW SHOULD THE COMPANIES ESTIMATE THE VALUE OF THE CAPACITY?

A. The companies should use the Effective Load Carrying Capability (ELCC) method to estimate the capacity credit or value of solar capacity. This method provides estimates of the capacity required for two alternative systems that provide the same level of reliability, one with and one without the pilot program solar power. To get the solar capacity value, the MW of capacity no longer needed but for the solar pilot program, would be valued at the company's incremental value of capacity based on its most recently acknowledged IRP.

Q. WHY THE ELCC METHOD?

A. The ELCC method assures the same hourly reliability with and without the SPV power. It calculates the reduction in capacity needs that leaves the retail customers indifferent regarding the hourly balancing of loads and resources.

Sub-hourly balancing needs should be considered under the costs of shaping and firming the intermittent nature of the PV power.

Q. HOW SHOULD EACH COMPANY DETERMINE THE VALUE OF THE CAPACITY THAT IS NO LONGER NEEDED?

A. Each company should value the capacity differently between periods of resource sufficiency and deficiency. If the company is resource sufficient, it should value the capacity at the market price for capacity, based on the month the capacity is available. If the company is resource deficient, it should value the capacity by the costs that it can avoid. In the deficiency period the capacity value for all of the three company IRPs is the avoided the cost of building a gas-fired combustion turbine

Q. AREN'T SOME ELEMENTS OF THIS APPROACH TO CAPACITY SIMILAR TO THE COMMISSION APPROVED METHOD OF CALCULATING RATES PAID TO QUALIFYING FACILITIES (QFS)?

A. Yes, with one difference. During the deficiency period, the proposed approach for capacity value for the SPV Pilot would be very similar to the PURPA approach. The major difference is that the capacity value would be scaled up to account for line losses. As long as the concept of opportunity cost is retained, there is nothing wrong with borrowing parts of the PURPA approach for solar resource value.

Q. BUT WHAT IF REDUCTIONS IN NET LOAD ARE NOT LARGE ENOUGH FOR THE COMPANY TO EFFECTIVELY DELAY THE CONSTRUCTION OF A NEW CT OR SELL MORE CAPACITY IN WHOLESALE MARKET?

A. This method provides a reasonable estimate of the value of capacity even if the company does not reduce its purchases or ownership of capacity based on reduced net loads during the deficiency period or if it does not sell more capacity during the sufficiency period. The incremental value to retail customers from increased reliability from the solar power should be equal to or above the incremental cost of the avoidable capacity or the market price of capacity. If not, the incremental purchase or ownership of capacity by companies would not be in the best interest of customers. If the value to customers of capacity were less than the market price, the company should be selling some of its existing capacity.

Q. HOW SHOULD THE COMPANIES ESTIMATE THE VALUE OF INCREMENTAL REDUCTIONS IN T&D LOSSES?

A. The reductions in incremental T&D losses for solar power should be greater than average line losses. Incremental losses (and reductions in losses from lower net loads) are higher at higher line loadings. Loadings are generally higher than average during the daytime in late spring and summer when most of the solar power is generated. Companies should use average losses from daytime periods of the appropriately weighted months of solar generation as an approximation of the incremental loss reduction from solar power. Application of the incremental loss percent would proportionally increase all other solar resource values.

Q. HOW SHOULD COMPANIES ESTIMATE THE OTHER ELEMENTS OF SOLAR RESOURCE VALUE LISTED ABOVE?

A. Staff withholds judgments on how these values should be estimated until after it has had time to review the companies' responses to Staff Data Requests that are due on June 4, and the testimony submitted by parties on June 7 on these issues.

ISSUE 4: INFORMATION PARTIES SHOULD FILE ON JUNE 28

Q. WHAT SHOULD PARTIES FILE ON JUNE 28?

A. Companies and other parties should file their views on what the Commission should order companies to include in their Nov. 1 filings on solar resource value. Where possible, the June 28 filing should include examples of how the values should be calculated.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UM 1559
WITNESS: Philip Carver

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualification Statement

June 7, 2012

WITNESS QUALIFICATION STATEMENT

NAME:	Philip H. Carver
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Policy Analyst
ADDRESS:	550 Capitol Street NE Suite 215 Salem, Oregon 97301-2115.
EDUCATION:	I have a bachelor's degree in economics from the University of California, San Diego and a Ph.D. in natural resource and utility economics from the Johns Hopkins University.
EXPERIENCE:	From 1978 to 1980, I was an assistant professor at Dartmouth College. From 1980 to 2008, I worked for the Oregon Department of Energy and testified in a number of OPUC dockets. From November 2008 to July 2008, I was the lead OPUC staff on the Renewable Portfolio standards rulemaking (AR 518). From May 2010 to the present, I have been in my current position with the OPUC. In this position, I have worked on issues related to renewable power and energy efficiency

PUBLIC UTILITY COMMISSION
OF OREGON

UM 1559

STAFF SURREBUTTAL TESTIMONY OF

PHILIP CARVER

In the Matter of
PUBLIC UTILITY COMMISSION OF OREGON
Investigation into the Appropriate Calculation of Resource Value for Solar Photovoltaic (PV)

July 19, 2012

CASE: UM 1559
WITNESS: PHILIP CARVER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 300

SURREBUTTAL TESTIMONY

July 19, 2012

Q. PLEASE STATE YOUR NAME.

A. Phil Carver. I previously filed testimony in this docket labeled Staff Exhibits 100 and 200.

Q. WHAT IS THE PURPOSE OF THIS SURREBUTTAL TESTIMONY?

A. I clarify final Staff positions on the elements of solar resource value. These elements are energy value, capacity value, wheeling costs, integration costs, avoided transmission and distribution (T&D) investments, the value of avoided fuel price volatility and reduced T&D losses.

Q. WHAT IS THE FINAL STAFF POSITION ON ENERGY VALUE?

A. Staff continues to support the forecasts of the Mid-Columbia wholesale power price for the high-load and low-load hour periods as the best estimate of the energy value. If a utility is buying power in that hour, the price is the avoided costs. If the utility is selling, the price is the opportunity cost of the wholesale sales made available by the production of solar photovoltaic (PV) power.

Q. WHAT FORECAST OF PRICES SHOULD UTILITIES USE?

A. In their November 1 filing utilities should use the most recent long-term forecast that the Oregon Commission has approved or is the base or average forecast from the most recently acknowledged integrated resource plan. There is no opportunity to vet a new long-term price forecast as part of the November 1 filing. These prices should be adjusted to include the base or average carbon adder that was used in the last Commission acknowledged integrated resource plan.

Q. WHY IS THE JOINT UTILITIES' PROPOSED USE OF RENEWABLE AVOIDED COST INAPPROPRIATE?

A. Portland General Electric (PGE) and PacifiCorp continue to defend the use of renewable avoided costs (Joint-Testimony/200, Brown – Macfarlane/3-5, 6-9). In addition to the reasons described in Staff Reply comments (Staff/100, Carver/4-5), renewable avoided cost is inappropriate because it reflects the ***cost*** of a different renewable resource that is avoided (currently ***wind*** for PGE and PacifiCorp), not the ***value*** of the ***solar*** power. ORS 757.360(5) clearly indicates the "resource value" is the "… value to an electric company of the electricity delivered from a ***solar*** photovoltaic energy system …" (emphasis added). Renewable avoided cost is the ***cost of wind*** to satisfy the renewable portfolio standard (RPS). Because the patterns of intermittency are very different for solar and wind, their ***value*** to the electric company will be different, especially their capacity value. It makes no sense to assert that the cost of wind power is the value of solar power. Solar PV power is real power that does more than just displace the need to purchase or build wind power to satisfy the RPS.

Q. WHAT ABOUT CAPACITY VALUE?

A. The Joint-Utilities and Idaho Power Corporation (IPC) did not rebut Staff's assertion that the ELCC method is recognized at the conceptually appropriate method to calculate capacity value (see Staff/100, Carver 9-11). If the calculation based on equal loss of load probabilities or un-served energy is too burdensome, utilities should use the Garver approximation.

Q. PLEASE DESCRIBE THE GARBER APPROXIMATION.

A. As described in a 2005 NREL paper:

> *Garver's 1966 paper is indeed a classic in the power system reliability literature. The Garver technique to estimating ELCC was applied to conventional generators and was developed to overcome the limited computational capabilities that were available at the time.*
>
> *The approach approximates the declining exponential risk function (LOLP in each hour, LOLE over a high-risk period). It requires a single reliability model run to collect data to estimate Garver's constant, known as m. Once this is done, the relative risk for an hour is calculated by*
>
> *R' = Exp{-[(P-L)/m]}*
>
> *where P = annual peak load, L = load for the hour in question, R' is the risk approximation (LOLP), measured in relative terms (peak hour risk = 1). A spreadsheet can be constructed that calculates R' for the top loads. Then modify the values of L by subtracting the wind generation in that hour. Calculate LOLE approximation for (a) no-wind case and (b) wind case by summing the hours. … Compare [this value] to gas plant or other benchmark, de-rated by its forced outage rate.*[1]

This calculation is not particularly burdensome. The data is not difficult to obtain data.

Q. WHAT SHOULD THE COMMISSION HAVE THE UTILITIES REBUTTABLY PRESUME FOR THE PERCENT OF SOLAR PV NAMEPLATE CAPACITY CONTRIBUTION TO CAPACITY?

A. The Commission should instruct utilities to include in their November 1 filing a solar resource value with an assumed capacity credit of 30 percent of the PV nameplate capacity. The Commission should also indicate that if an electric company wishes to advocate for an alternative capacity credit, the company should also supply a solar resource value that incorporates the proposed

[1] M. Milligan and K. Porter; NREL, "Determining the Capacity Value of Wind: A Survey of Methods and Implementation"; May 2005; http://www.nrel.gov/docs/fy05osti/38062.pdf

estimate with appropriate documentation supporting their value instead of the 30 percent value.

Q. WHY 30 PERCENT CAPACITY CREDIT?

A. A 30 percent value was calculated in a study using PGE data and the Garver method with a value for "m" of 3 percent. The study was funded by the US Department of Energy as part of the Solar America Initiative using data for PGE.[2] Because PacifiCorp and IPC consistently have their system peak hour in the summer, their capacity credit percentage should be higher than PGE's. The study used data from a year with a summer to winter peak ratio of 1.01. This ratio is a good basis for solar valulation for PGE for the 2012 to 2027 period, because PGE's system will soon be consistently summer peaking. This change will be due to reduced space and water heating use from energy efficiency measures, increasing air-conditioning loads and rising temperatures from increased concentrations of greenhouse gases in the air.

Q WHAT ABOUT THE PROPOSAL BY PGE AND PACIFICORP REGARDING CAPACITY VALUE THAT THE SOLAR RESOURCE VALUE SHOULD BE CONSISTENT WITH "PREVALING AVOIDED COST" AS DEFINED IN UM 1129 (JOINT-TESTIMONY/200, BROWN – MACFARLANE/7-9)?

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[2] See the value on the graph for low PV penetration for PGE on page 6 of R. Perez, M. Taylor, T. Hoff, JP Ross, *Reaching Consensus in the Definition of Photovoltaics Capacity Credit in the USA: A Practical Application of Satellite-Derived Solar Resource Data* IEEE Journal on Selected Topics in Applied Earth Observations and Remote Sensing. Vol. 1, no. 1, 2008. (available at http://www.asrc.cestm.albany.edu/perez/publications/Utility%20Peak%20Shaving%20and%20Capacity%20Credit/Papers%20on%20PV%20Load%20Matching%20and%20Economic%20Evaluation/Towards%20reaching%20consensus-08.pdf)

A. If the Commission had intended to simply apply existing PURPA avoided costs when calculating the solar resource value, it would have made no sense for them to open this docket. The Commission could simply have made that statement in Order No. 11-339. By opening this docket the Commission indicated an interest in the views of the parties about **how** solar resource value should be estimated, as distinguished from currently-approved avoided costs. The rule cited by the Joint Utilities in OAR 860-084-0240(1)(a) indicates that the Commission will designate **an** avoided cost rate at the end of the 15 year contract period. The rule does not preclude the Commission from setting an avoided cost rate specific to solar PV power. As noted above, a different resource value for solar, as distinguished from wind or other resources, is implicit in the Legislature calling for the Commission to determine a **solar** resource value.

Q. WHY IS IT APPROPRIATE TO ADD CAPACITY VALUE TO THE WHOLESALE PRICE OF ENERGY?

A. During both capacity deficiency and sufficiency periods an electric company will have an opportunity to sell excess power or reduce its purchases. These opportunities are independent of whether or not a company needs additional capacity. I do agree that it is impractical to estimate the value of opportunities to sell capacity during the sufficiency period due to the lack of an effective capacity market in the Pacific NW.

Q. WHAT ABOUT WHEELING COSTS?

A. On further consideration, wheeling costs should not be added to the wholesale price. This is because during hours where a company is a net seller, the wheeling rate should be subtracted from the wholesale power cost to determine the value of power when an electric company. As it cannot be determined that all companies will only be buying when the solar power is produced, it would be inappropriate to simply add wheeling costs to the wholesale power rate when calculating the energy value.

Q. WHAT ABOUT INTEGRATION COSTS AND AVOIDED T&D INVESTMENTS?

A Staff retains the position in Staff 200, Carver/3 that these costs and avoided costs are likely small and offsetting. The Commission should instruct the companies to calculate solar resource value with both values set to zero. The Commission should give the companies an opportunity to make and defend an alternative calculation.

Q. WHAT ABOUT THE VALUE OF AVOIDED FUEL PRICE VOLATILITY?

A. Staff retains the position in Staff 200, Carver/5-6 that a nominal levelized Opal Hub natural gas price $5.15 per MMBtu should be used to estimate the value of the fixed-price long-term natural gas that is freed-up by the solar PV power. As noted in Staff 200, a company may also provide an estimate of this element of solar resource value based on its experience buying long-term natural gas.

Q. WHAT ABOUT THE VALUES FOR T&D LOSSES?

A. Staff now supports using average losses. Staff is persuaded by the idea of Joint-Testimony/200, Brown – Macfarlane/10 that while summer daytime incremental losses will tend to be higher than average losses, this effect is at least partially counterbalanced by local losses that occur when solar power exceeds the customer's load and power flows to a neighboring customer.

Given that the peak hour losses are not very different from average losses for the three companies, average loss values are a good approximation for calculating solar resource value. PacifiCorp and PGE should use the loss values in Joint-Testimony, Brown – Macfarlane, 101/1 and 102/3, of 9.18 and 6.14 percent, respectively. IPC should use the loss value of 10.9 percent of Idaho Power/200, Allphin/5.

Q. WHAT ABOUT THE CONCERN EXPRESSED AT IDAHO POWER/200, ALLPHIN/5 THAT "THE ESTIMATED T & D LINE LOSSES WILL NOT RESULT IN IDAHO POWER CHANGING ANY OF ITS TRANSMISSION DISTRIBUTION OR POWER SUPPLY PLANNING PROCESSES …"?

A. Staff does not see how threshold issues for planning processes are related to avoiding line losses when loads are reduced by solar power at a customer's site. Reduced load automatically translates into reduced generation. Line losses reductions occur automatically.

PGE and PacifiCorp support the use of average losses to calculate solar resource value. There is no distinguishing characteristic of IPC that would indicate that solar resource value should not be adjusted for line losses.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

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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 METHODOLOGIES FOR CALCULATING PUBLISHED AVOIDED COST RATES.	CASE NO. GNR-E-11-03

CLEARWATER PAPER CORPORATION
J.R. SIMPLOT COMPANY
EXERGY DEVELOPMENT GROUP OF IDAHO, LLC

DIRECT TESTIMONY OF DR. DON READING

May 4, 2012

INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Don Reading and my business address is 6070 Hill Road, Boise, Idaho. I am a principal with Ben Johnson Associates.

Q. HAVE YOU PREPARED AN EXHIBIT OUTLINING YOUR QUALIFICATIONS AND BACKGROUND?

A. Yes. **Exhibit No. 501** serves that purpose.

Q. On whose behalf are you testifying?

A. I have been retained by the Clearwater Paper Corporation, the J. R. Simplot Company and Exergy Development Group of Idaho.

Q. WHAT ARE THE INTERESTS OF THOSE THREE ENTITIES IN THIS DOCKET?

A. Clearwater Paper Corporation owns a large paper manufacturing facility near Lewiston, Idaho. As part of its operations it generates electricity and sells that electricity to Avsita as a qualifying facility (QF) under the Public Utility Regulatory Policies Act of 1978 (PURPA). Cogenerating power at the Lewiston facility helps make it more profitable and stable. This is important because Clearwater is Nez Perce County's single largest employer. Clearwater directly employs about 1,300 people in Lewiston, almost seven percent of the total Nez Perce County workforce. If it were to close, Nez Perce County's unemployment rate would double from six and a half percent to almost fourteen percent. Clearwater is in the process of negotiating an extension of its existing contract with Avista. That contract expires next year. So it is very interested in the outcome of this dock

The J. R. Simplot Company generates electricity at its Pocatello, Idaho phosphate fertilizer facility. It sells its electricity to Idaho Power under a PURPA contract that is set to expire next year. Like Clearwater in Lewiston, Simplot is a major employer in Pocatello. It employs almost 350 people directly in the facility and another 200 at its Smokey Canyon Mine All of the Smokey Canyon Mine's production is delivered to the Simplot Pocatello facility. These five hundred and fifty jobs are made more secure and stable due to Simplot's ability to sell its electricity to Idaho Power.

Exergy Development Group of Idaho is a successful renewable energy developer throughout the country. Its main office is in Boise, Idaho. It is responsible for bringing hundreds of megawatts of wind energy projects on line in Idaho over the past several years. It developed the very first utility scale wind project in the state. Exergy is obviously very interested in the outcome of this docket as its business model is, in part, based on PURPA.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS CASE?

A. My testimony will address both to the avoided cost methodologies that I recommend should be utilized by the Idaho Public Utilities Commission (Commission) to set standard and non-standard avoided cost rates, as well as other QF issues. In Part 1 of my testimony, I will first address why I believe the Commission should not make significant revisions to the surrogate avoided resource (SAR) methodology for standard or published rates, and then I will address the

Commission's implementation of IRP Methodology rates for projects above the eligibility cap for published rates. In this section of my testimony I recommend to the Commission:

(1) That no deficit period be allowed and that QFs should receive capacity payments for the full term of their contract;

(2) That if the IRP is going to be used for setting rates that it needs to be litigated before the Commission through the hearing process;

(3) That input variables not be allowed to change between approved IRPs with the exception of natural gas prices forecasts from a third party transparent source; and

(4) That the single model run method proposed by Idaho Power be rejected.

In Part 2 of my testimony, I will address other issues related to PURPA and QF contracts. I will explain why I recommend the Commission adopt or reaffirm the following QF policies:

(1) That liquidated damages provisions in QF contracts be tied to an estimate of a utility's actual damages, and that QF contracts should likewise contain terms protecting QFs in the event of a utility default;

(2) That QFs not be required to achieve on line status within 2 years of signing a contract;

(3) That the standard term available for QF contracts remain at 20 years;

(4) That Idaho Power's economic curtailment tariff proposed for existing and new QFs not be approved;

(5) That a QF contracting tariff contain meaningful contract negotiation guidelines and fair standard contracts for QFs choosing to sell their output on a nonfirm basis and those choosing to sell pursuant to a legally enforceable obligation;

(6) That QFs own environmental attributes in Idaho QF contracts because the avoided cost rates do not compensation the QFs for more than the energy and capacity alone; and

(7) That QFs will receive the same credit for transmission level upgrades necessitated for their interconnection as non-QF generators and utility-owned resources.

PART 1: AVOIDED COST RATE CALCULATIONS

I. PUBLISHED RATES

Q. DO YOU BELIEVE THERE ARE ANY COMPELLING REASONS FOR THE COMMISSION TO CHANGE COURSE BY USING THE INTEGRATED RESOURCE PLAN (IRP) METHODOLOGY INSTEAD OF THE SURROGATE AVOIDED RESOURCE (SAR) FOR SMALLER PROJECTS?

A. No. The proxy or SAR method for determining a utility's avoided cost rates was the method adopted by the Commission in 1980 when it first addressed its obligation to implement the then new federal law. In my opinion, the SAR methodology has been a successful, transparent and effective method for estimating a utility's avoided cost rates.

Q. WHAT DID THE COMMISSION SAY ABOUT THE SAR METHODOLOGY WHEN IT FIRST ADOPTED IT?

A. The Commission made it clear that it was laying a solid foundation for determining avoided cost rates for the utilities it regulates by saying:

> 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.[1]

In this Order the Commission stressed that the price offered to QFs must be set at level that would foster a competitive market or the utility would be left to dictate the price. The SAR or proxy methodology was re-litigated in 1989 in Case No. U-1500-170. In that case the Commission stated:

> We find no avoided cost methodology presented in this case that is pragmatically superior to the existing surrogate avoidable resource (SAR) method. Nor do we find a method for determining the estimated time of load-resource balance that is superior to using each specific utility's most recent load- resource plan (as incorporated in its Resource Management Report) as the basis for a Commission determination establishing surrogate utility specific resource plans following public hearing. Furthermore, we find that the most appropriate surrogate resource for determining avoidable long term costs for utilities operating in Idaho is a single hypothetical coal-fired steam plant with state of the art emission controls. A surrogate resource is merely a means of estimating the value of energy and capacity. The proxy unit need not actually be within a utility's resource plan.[2]

In that case none of the parties opposed the use of the proxy method and, indeed, all supported

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1 IPUC Order 15746, Case No. P-300-12 (1980).
2 IPUC Order 22636, pp. 67-68, Case No. U-1500-179 (1989).

the SAR methodology. Commission Staff in particular was helpful, as the Commission observed in its order,

> Staff admits that any method of administratively establishing avoided costs is "based, at least in part, upon a fiction." In no small part, this is due to the vagaries of forecasting. One of the advantages cited by Staff in the present SAR methodology is that it does not require a detailed analysis of utility planned resources. Staff contends that a single Idaho avoided cost rate would have the advantage of simplicity of application and administration. Although the SAR method was described as consisting of seven steps, implementation of those steps requires the Commission to establish at least 29 variables for computing avoided costs. The set-point for most variables is selected from a range of reasonable values.
>
> Staff recommends (1) maintaining the existing method of computing avoided costs, (2) establishing a single avoided cost rate for all Idaho [sic.], and (3) establishing an automatic method of periodically revisiting the variables.[3]

Numerous IPUC cases can be cited describing the rational for using the SAR methodology as a reasonable and transparent method for determining avoided cost rates for the state's investor-owned utilities.

Q. HAVE THERE BEEN ANY MAJOR CHANGES TO THE SAR METHODOLOGY SINCE IT WAS FIRST ADOPTED BY THE COMMISSION IN 1980?

A. Yes. The one major change was in a 1993 case.[4] In that case, the Commission concluded that the avoidable resource should be changed to a natural gas-fired combined-cycle combustion turbine rather that a coal-fired generating plant.

Q. IT HAS BEEN THIRTY TWO YEARS SINCE THE SAR WAS FIRST ADOPTED

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[3] *Id.*. at pp. 10-11.

[4] IPUC Order 25926, Case Nos. IPC-E-93-28, PPL-E-93-5, UPL-E-93-7, UPL-E-93-3, PPL-E-93-3, WWP-E-93-10 (1995).

BY THE COMMISSION, HAVE CONDITIONS CHANGED SUCH THAT IT IS NO LONGER RELEVANT FOR ESTIMATING AVOIDED COST RATES?

A. No. Quite the opposite, in fact. Idaho's energy picture has vacillated dramatically over the past three decades. We have had periods of surplus and periods of deficit. We have experienced periods of high load growth and low or even at times negative load growth. We have had periods of high inflation and low inflation. We have had droughts and record water years. The SAR methodology has been robust through all of those changes and has produced avoided cost rates that have proven to be remarkably accurate in hindsight. Currently, I do not see any conditions that would constitute a compelling reason to change Commission precedent at this time by abandoning the SAR for setting avoided cost rates.

Q. WHAT POSITION HAVE THE UTILITIES TAKEN IN THIS DOCKET RELATIVE TO THE SAR METHODOLOGY?

A. In addition to my testimony discussing the utilities positions, I have also included **Exhibit No. 502**, which includes several discovery responses regarding the avoided cost rates. Idaho Power is an outlier in that it is the only utility recommending the SAR methodology be abandoned. Both Rocky Mountain Power and Avista advocate maintaining the SAR methodology for standard contracts while supporting a cap of 100 kw for wind and solar projects to be eligible for published rates. According to the testimony of Rocky Mountain Power's witness Kelcey Brown:

> The Company's position is that the current implementations of the SAR and IRP methodologies are appropriate for the published and negotiated avoided cost rates, respectively, as long as the 100 kW eligibility cap threshold for wind and solar QFs is maintained for published SAR rates. The SAR methodology used for calculating published avoided cost rates for smaller QFs continues to provide a simple and transparent means of pricing that minimizes transaction costs a very small QF might incur to negotiate a power purchase agreement. However, the SAR methodology is not the best methodology as the QF project capacity increases since it does not take into consideration the value a specific QF project would provide to each utility's unique power system and does not account for the characteristics of each individual QF.[5]

I certainly agree with Ms. Brown in that the SAR methodology continues to provide a simple and transparent means of pricing and that it helps to keep the transaction costs down. I would add, however, that the benefit of reduced transaction costs inures to both the QF developer AND the utility.

Q. IS THE SAR METHODOLOGY WIDELY ACCEPTED?

A. Yes, even Idaho Power witness William Hieronymus seems to agree. He cites a 1992 National Economic Research Associates (NERA) survey that he states might be 20 years old but, "still is representative of administratively determined avoided methods in use today."[6] This survey indicated that 14 states, out of 49 surveyed used some form of the proxy method in determining avoided cost rates for PURPA projects. This indicates the SAR method is widely accepted as valid method for determining avoided cost rates.

Q. WOULD YOU DISCUSS THE THREE UTILITIES' RESOURCE ACQUISITION

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5 Direct Testimony of Kelcey Brown, GNR-E-11-03, pp. 4-5.

6 Direct Testimony of Idaho Power Witness William Hieronymus, GNR-E-11-03, pp. 59-60 (citing Parmesano, Hethie and Bridgman, William, *The Role and Nature of Marginal And Avoided Costs in Ratemaking; A Survey*, NERA (January 1992).

HISTORY AS IT RELATES TO A COMBINED CYCLE COMBUSTION TURBINE?

A. Yes. Each of the three utilities have either recently added or will add a CCCT to their generating system. It is clear that a CCCT is the resource of choice. Idaho Power is planning to bring Langley Gulch on line in June 2012, with its next thermal unit being a combustion turbine in 2022 followed by a CCCT in 2025.[7] Avista purchased the output of the Lancaster combined-cycle generating station through a tolling agreement in 2007 and while the Company's next CCCT is not planned until 2023 there is a combustion turbine in their preferred strategy in 2018.[8] PacifiCorp has a CCCT F Class scheduled to come on-line in 2014 and a CCCT H Class planned for 2016.[9] For the three investor-owned electric utilities in Idaho, as well as most of the rest of the country, a CCCT is the resource of choice for base load plants for planning purposes and hence it remains the reasonable choice for the proxy unit for the SAR.

Q. BEFORE YOU DISCUSS THE UTILITIES' RECOMMENDATIONS IN THIS DOCKET WOULD YOU PLEASE DISCUSS SOME OF THE UNIQUE ASPECTS OF AN ELECTRIC UTILITY'S AVOIDED OR MARGINAL COSTS AS ITS POWER SYSTEM GROWS?

A. Yes. Due to required lead times, economies of scale, efficiency, etc., utilities tend to add plant in relatively large increments. This means in actual practice, generation capacity is periodically added in a "lumpy" fashion. Hence, at any given time, an actual system will have a

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7 Idaho Power Company's 2011 Integrated Resource Plan, p. 7.
8 Avista Corporation's 2011 Integrated Resource Plan, p. viii.
9 PacifiCorp's 2011 Integrated Resource Plan, p. 8.

bit more, or a bit less, than the optimal amount of generating capacity. Because generating resources tend to be added to actual systems in relatively large MW increments (e.g. 100 MW or more), and even if units are carefully sized to correspond to the system size, and expected rate of load growth, it is too much to expect the mix of different types of generating plants to be precisely optimum.

As Commissions around the county were struggling with the implementation of PURPA, NERA produced a series of publications that became known as the "Grey Books." Although these Grey Books were published just prior to the passage of PURPA, commissions and utilities around the country used them in implementing PURPA because they set forth the theoretical basis for quantifying a utility's marginal costs. These "Grey" books provided much of the theoretical background that was used in establishing avoided cost rates by regulatory commissions. As explained by NERA in one of the "Grey Books", because capacity is added in discrete blocks with long lead times, marginal costs fluctuate around the utilities long-run least cost growth path.

Because of this fluctuation, in some years the short run operating costs may fall short of what is needed to recover the total cost of building and operating a new generating unit – but in other years, particularly just before the time when a new base load generating plant needs to be added to the system, one would expect the marginal running costs of the system to be much higher. This phenomenon is critical in defining avoided costs for a utility because of the way it affects avoided or marginal costs in various time periods.

Q. COULD YOU DESCRIBE WHAT YOU MEAN WHEN YOU STATE THAT VARIOUS TIME PERIODS NEED TO BE CONSIDERED IN THE DETERMINATION OF AVOIDED COST RATES?

Consideration of the time dimension in the consideration of marginal generating capacity costs are outlined in the Topic 4 "Grey Book" referenced above. The publication discusses the implications of using long-run and short-run marginal capacity costs

> A. The long-run marginal generating capacity cost is the cost of the generating unit that, in an optimal (least total cost generating mix) system, would be added to accommodate increased peak-period demands. Depending upon the utility's load duration curve and the natural resources available to the utility, this unit will most likely be a combustion turbine, a pumped storage project, a cycling (daily) fossil unit or an additional water wheel at an existing hydro site.
>
> B. The short-run marginal capacity cost will be the shortage cost for hours not served. Theoretically, on an annual basis, if the expected shortage cost equals or exceeds the cost of peaking capacity, system expansion will occur.
>
> C. Due to the fact that capacity is acquired in discrete blocks and long lead times are required, utilities will oscillate around the least total cost expansion curve. Rather than follow the short-run costs in their oscillations around equilibrium, *it is recommended that, for marginal costing purposes, the long-run marginal costs of generating capacity be used* except in chronic cases of imbalance. (*emphasis added*)[10]

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

[10] NERA, *How to Quantify Marginal Costs, Topic 4, Electric Utility Rate Design Study*, pp. 2-3 (March 1977).

always have a capacity surplus. Unless QFs are credited for long-run capacity costs they will never by compensated on <u>an</u> <u>equal</u> <u>basis</u> relative to what the utilities receive in rates to build plant.

Q. YOU HAVE STATED THE NEED FOR THE TIME DIMENSION TO BE TAKEN INTO ACCOUNT IN THE DETERMINATION OF AVOIDED CAPACITY RATES. IS THE SAME TRUE FOR DETERMINING AVOIDED ENERGY COSTS?

A. Yes. That same NERA Topic 4 "Grey Book" explains why the calculation of marginal energy costs should also take into account the oscillations around a utility's least cost planning path.

> In the case of systems oscillating around an optimal generating mix equilibrium, it is *desirable to analyze marginal energy costs over a full cycle of oscillation, usually five to ten years into the future.* (*emphasis added*)[11]

Idaho Power's proposed method for determining avoided energy costs (discussed in more detail below) uses a very short-run hourly marginal cost calculation.

> Q. Are there times when the incremental cost calculated with Idaho Power's proposed methodology goes to zero?
> A. Yes, and this is not unrealistic. Considering the minimum load levels established for the thermal generating resources, and the amount of non-dispatchable QF generation on Idaho Power's system, there may be hours during low load periods when Idaho Power's avoidable incremental costs are zero. In fact, there could be times when Idaho Power's avoided incremental costs would be negative.[12]

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11 *Id.*, p. 4.

12 Direct Testimony of Idaho Power Witness Karl Bokenkamp, GNR-E-11-03, p. 14.

Including these "avoidable incremental costs" as part of the calculation of avoided energy cost, as in the case of avoided capacity costs described above, does not put the QF on an equal cost footing with the utility's own resources. In any given hour the utility is incurring energy costs to produce power to serve loads that are being passed on to customers. When the utility requests a certificate from the Commission to build plant it includes its expected fuel costs for the plant at an assumed capacity factor. What the utility does not do is add the plant to its resource stack and then ask for recovery based on the highest cost resource it may be replacing on an hourly basis.

Q. EACH OF THE UTILITIES IN THIS DOCKET ARE ADVOCATING THAT QFs SHOULD NOT BE ELIGIBLE FOR CAPACITY PAYMENTS WHEN THE UTILITY'S FORECASTS DETERMINE THAT CAPACITY IS NOT NEEDED. GIVEN YOUR EXPLANATION OF THE "LUMPY" NATURE OF A UTILITY'S INVESTMENTS, DO YOU HAVE A POSITION ON THAT ISSUE?

A. Yes. As I have explained above, a utility will add plant in increments that will exceed its short term needs to serve load. Therefore, unless due to some unforeseen factor or under-forecasting, a utility will almost always be surplus for the next few years. As noted in Avista witness Clint Kalich's Direct Testimony, the Commission explicitly dealt with first deficit year or surplus period issue in Order 29124. In that Order the Commission concluded:

> The continued importance of a first deficit year in avoided cost calculations has to be weighed against the improbability of settling on a surplus period in which anyone has confidence. Utilities have had the opportunity to instill confidence in the first deficit year but in failing to update for changes in load/resource balance have compromised the public confidence in the reasonableness of its continued use. It is a factor in avoided cost calculation, the

> Commission finds, that needs to be taken into account only to the extent practicable. Reference 18 C.F.R. 292.304(e). The record supports a finding that continued use of the first deficit year is administratively burdensome and no longer practicable. . . . . We find it appropriate to create an avoided cost that contains the full value for both energy and capacity.[13]

The Commission also noted in that same Order that one of the intervenors, Plummer Forest Products, offered a metaphor for a utility's surplus period:

> It was also suggested by Plummer that it poses a "Catch 22" dilemma – i.e., a utility only has to purchase if it's deficit; however, a utility can extend its surplus by constructing its own resources, so a utility is never deficit and never has to purchase.[14]

A "Catch 22" dilemma is an apt phrase for the trap that a QF faces when it is denied capacity payments when a utility claims it is in surplus. As pointed out above 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.

Q. IN HIS DIRECT TESTIMONY AVISTA'S WITNESS KALICH INDICATES THINGS ARE DIFFERENT NOW THAN THEY WERE IN 2002 WHEN THE COMMISSION ISSUED ORDER NO 29124 AND GOES ON TO REBUT THE NINE REASONS OUTLINED BY STAFF FOR THE ELIMINATION OF THE DEFICIT PERIOD. DO YOU HAVE ANY COMMENTS REGARDING MR. KALICH'S TESTIMONY?

A. I will not comment point for point on his rebuttal points but, taken as a whole, his

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[13] IPUC Order No. 29124, GNR-E-02-01 (2002).
[14] *Id.*.

arguments do not justify eliminating capacity payments to a QF during surplus periods. I will focus on three points; first his assumed definition of "true avoided cost," second the difference between "surplus" energy rates and rates identified in an SAR, and third that the utilities' IRPs are subject to "significant oversight."

Mr. Kalich addresses the point that utilities are likely to be surplus in the near term (point 7). Mr. Kalich States:

> The seventh concern was that utilities tend to be surplus in the near term, and that avoided cost rates should not provide incentives for a utility to increase its length to avoid having to purchase PURPA power. It is often true that utilities are surplus in early years; being so is an essential part of providing reliable utility service. It also is true that QF developers would be affected by these surpluses were they to receive lower early-year payments during surplus years. But this effect is a reflection of ***true avoided costs***. (*emphasis added*)[15]

Given the discussion above about "lumpy" utility investment, I certainly agree with the first part of the above statement that utilities tend to be surplus in the near term. However, also as discussed previously, I strongly disagree that QFs receiving lower early-year payments are a reflection of "true avoided costs." Avista apparently believes "true avoided costs" means QFs seldom are compensated for capacity payments for their facilities in the early years while the Company's own generation plant receive recovery of full capacity for the full term of the plant life.

Q. THE SIXTH CONCERN EXPRESSED BY STAFF WAS THAT THE DIFFERENCE BETWEEN PURPA RATES AND "SURPLUS" ENERGY HAD

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[15] Direct Testimony of Avista Witness Clint Kalich, GNR-E-11-03, pp.13-14.

NARROWED AND HENCE THERE WAS LESS JUSTIFICATION FOR DISTINQUISHING THE DIFFERENCE. DO YOU AGREE WITH THAT CHARACTERIZATION?

A. Yes and no. At this time there are significant differences between SAR set rates and the surplus energy rates. However over the past 30 years that PURPA rates have been in place in Idaho there have been periods where market rates have been both less than and greater than SAR set rates. At this time, the price of natural gas tends to drive electric rates. While current gas rates are very low, natural gas rates have tended to be extremely volatile over time and, as pointed out above, avoided cost rates should reflect the long-run marginal costs for a utility.

Mr. Kalich believes this concern is made moot if his recommendation for bifurcating energy and capacity payments to a QF is adopted. He proposes capacity payments for a QF calculated on a per-MW "on-peak contribution" basis. Mr. Kalich's proposal seems to disregard the FERC requirement that avoided cost rates must consider the individual and aggregate value of energy and capacity from the fleet of qualifying facilities on the utility's system.[16]

Q. MR. KALICH INDICATES THE FIRST FOUR CONCERNS OF STAFF ARE NO LONGER VALID BECAUSE THE UTILITIES EACH FILE AN IRP EVERY TWO YEARS THAT ARE "SUBJECT TO SIGNIFICANT OVERSIGHT." DO YOU AGREE THAT THE REQUIRED FILING OF AN IRP EVERY TWO YERS IS SUFFICIENT REASON TO ALLEVIATE STAFF'S CONCERNS?

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[16] 18 C.F.R. § 292.304(e)(vi).

A. I would agree if the utilities IRP's were, in fact, "subject to significant oversight" in their development and submission. The Idaho Commission only accepts each utility's IRP for filing; it does not approve the utility's conclusions. The following Commission statement is taken from Idaho Power's 2011 IRP. It is typical for all Idaho IOUs:

> Based on our review, we find it reasonable to accept for filing and to acknowledge Idaho Power's 2011 Electric Integrated Resource Plan. Our acceptance of the 2011 IRP should not be interpreted as an endorsement of any particular element of the Plan, nor does it constitute approval of any resource acquisition contained in the Plan.[17]

It is significant that the Commission states it's acceptance for filing of the IRP does not constitute approval of any resource acquisition nor even an endorsement of any particular element in the plan. It is true the utilities have instituted a public process in the development of their IRPs along with forming consumer advisory groups. However, an IRP contains a large number of very complex and technical aspects that lay advisory groups do not have the time or expertise to thoroughly critique.

Q. DR. READING, WHAT DO YOU RECOMMEND IN THE FUTURE FOR DEVELOPMENT OF IRPs?

A. IRPs are becoming increasingly relied upon for a wide number of important regulatory issues. These uses include justifying adding resources, establishing avoided costs, determining periods of deficit and surplus, projecting load growth, and measuring cost effective DSM, etc.

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[17] IPUC Order No. 32425, Case No. IPC-E-11-11 (2011).

Given the importance of the IRP in justifying utility expenditures and its ultimate impact on customer rates it is essential that the IRP be subject greater scrutiny and subjected to a litigated hearing and ultimately approval by the Commission. Only after the IRP is subjected to thorough examination should its various conclusions be accepted for rate setting purposes.

Q. HOW DOES AVISTA RECOMMEND CALCULATION OF CAPACITY COSTS?

A. As discussed in the last section, Avista's Mr. Kalich is recommending bifurcating energy and capacity payments to QFs. He proposes capacity payments for a QF be calculated on a per-MW "on-peak contribution" basis. This is accomplished by converting the SAR per MWh payment level to a total annual capacity payment that is divided by the expected annual capacity factor. For PURPA projects eligible for published avoided cost rates, rather than using capacity based on the SAR, he advocates calculating capacity payments based on the nature of the project. In addition he recommends these separate capacity amounts based on the type of project be calculated on a per MW basis and then "translated" to a dollars per MWh that is added to the per MWh energy rate to determine avoided cost. He also asks that once the SAR capacity payment is calculated it serve as a cap on total payments for any given year to prevent a QF from underestimating its energy output.

Q. DO YOU AGREE WITH THESE CHANGES AVISTA IS ADVOCATING FOR THE CALCULATION OF CAPACITY PAYMENT FOR QFs ELIGIBLE FOR PUBLISHED RATES?

A. The process adds unneeded and unnecessary complexity to the calculation of avoided costs for published rates. As pointed out above, especially for smaller QFs eligible for published rates the computing of avoided costs should be as simple and straight forward as possible. It should be transparent and understandable. In my opinion, he is solving problems that do not exist.

Q. DO YOU AGREE WITH ANY OF MR. KALICH'S RECOMMENDATIONS?

A. I agree with his recommendation that the Commission should use the regularly updated gas forecast generated by the Energy Information Administration (EIA) in its Annual Outlook Report as the forecast by which the Commission updates the published gas SAR avoided cost rates.[18] The Commission currently uses the irregularly published gas forecast generated by the Northwest Power and Conservation Council.

Although the Northwest Power and Conservation Council's forecast can provide a stable rate for QFs, it can be difficult for QFs to know when to expect the rates to go up or down. I believe all parties, including QFs, the Commission, and the utilities, could benefit from a predictable rate change at a predetermined date each year occurring within a reasonable time period of the regularly released EIA Outlook Report. The full report appears to be released in the spring. I recommend that the Commission clearly state that the rates each year will be updated on a specific date each year, such as on June 1, whether the rates are going up or down. I believe this recommendation addresses the utilities' concern that the existing gas price updates

[18] Direct Testimony of Avista Witness Clint Kalich, GNR-E-11-03, p. 34.

are too infrequent, and would provide parity in the timing of the rate increases and decreases.

II. NON-STANDARD RATES FOR QFs ABOVE THE ELIGIBILITY CAP

Q. THE THREE IDAHO IOUs IN THIS DOCKET HAVE FILED WHAT THEY CHARACTERIZE AS THE COMMISSION APPROVED "IRP METHODOLOGY" FOR THE DETERMINATOIN OF AVOIDED COST RATES. WOULD YOU PLEASE DISCUSS THE APPROACH EACH UTILITY HAS RECOMMENDED TO THE COMMISSION FOR APROVAL?

A. I examined the three proposals and compared them against the Commission Staff's "IRP Methodology" for determining a utility's avoided cost for PURPA projects in Idaho that the Commission approved in Case No. IPC-E-95-09. The methods put forth by the utilities vary significantly. RMP follows the approved methodology fairly closely. Idaho Power, however, takes an entirely different approach.

Q. WOULD YOU PLEASE EXPLAIN IN MORE DETAIL WHAT YOU MEAN WHEN YOU STATE THAT THE APPROVED IRP METHODOLOGY IS NOT BEING FOLLOWD BY ALL OF THE UTILITIES?

A. Before analyzing each of the utilities' proposals, an examination of the generally accepted approaches to calculating avoided costs needs to be considered. Idaho Power witness William Hieronymus in this direct testimony reviews what he refers to as the taxonomy of administrative methods for setting avoided costs as set forth in a report by the Edison Electric

Institute (EEI) that examined the setting of avoided costs.[19] The paper was prepared by the Brattle Group. The three methods found in the EEI paper also match those found in the survey by NERA discussed above.

Q. COULD YOU PLEASE BRIEFLY DESCRIBE THESE THREE METHODS THAT HAVE BEEN USED BY REGULATORY COMMISSIONS IN THE DETERMINATION OF AVOIDED COST RATES FOR PURPA PROJECTS?

A. State public utility commissions have used three basic approaches for determining avoided costs since the enactment of PURPA in 1978. Various states have employed various incarnations of these three basic approaches, as pointed out in the NERA survey for finding avoided costs for utilities under their jurisdiction. The three methods are: 1) the Peaker Method, 2) the Proxy Method, and the 3) Differential Revenue Requirement Method.

Q. WOULD YOU PLEASE DESCRIBE THE PEAKER METHOD?

A. Yes. When using the Peaker Method, the utility's power supply model is run with and without the given facility, at zero cost, to produce variable costs. Then, the capital costs of a peaking unit on a MWh basis is added to variable costs to find a utility's avoided costs.

Q. WHAT IS THE PROXY METHOD?

A. Under the Proxy Method (which is currently used in Idaho for published rates), the capital costs of the proxy unit are included, along with operation and maintenance expenses including fuel, as part of the calculations to find the utility's avoided cost. The assumption is

[19] Edison Electric Institute, *PURPA: Making the Sequel Better than the Original* (December 2006).

these calculated costs are a "proxy" for what the utility would incur to build the unit and therefore are a reasonable estimate of its avoided cost.

Q. THE THIRD APPROACH YOU MENTIONED IS THE DIFFERENTIAL REVENUE REQUIREMENT METHOD. WOULD YOU PLEASE EXPLAIN THIS METHOD?

A. Yes. The Differential Revenue Requirement Method calculates the utility's total generation costs (or revenue requirement) with, and without, the proposed facility. This method first uses an expansion plan model to generate expansion plans with and without the proposed facility. The method then uses the two different expansion plans as inputs to a financial planning model to produce the utility's revenue requirement with and without the proposed facility's output provided as free energy. That financial model would include items such as interest costs, taxes, allowed rate of return on the change in rate base and capital and other "rate case" inputs for the facility. The difference in the present value of the revenue requirement is the avoided revenue requirement component and is, in theory, the utility's full avoided cost, including avoided energy and capacity costs, as well as taxes and other cost factors.

The Commission accepted the Differential Revenue Requirement Method for finding avoided cost rates for QFs larger than 1 MW in Case No. IPC-E-95-9. The Commission approved a stipulation in that case that was signed by the three utilities, Commission Staff, and Rosebud Enterprises, Inc. Other parties in that docket chose not to sign the stipulation, but they did not oppose the methodology. Attached to Commission Staff witness Sterling's Direct

Testimony filed in that case is Exhibit 101 that contains Staff's proposed avoided cost methodology that was accepted by the Commission. This is the approach that is being commonly referred to as the "IRP Methodology" for Idaho utilities.

Q. WHY DO YOU SAY THE DIFFERENTIAL REVENUE REQUIREMENT METHOD IS ESSENTIALLY THE METHOD APPROVED BY THE COMMISSION IN CASE NO. IPC-E-95-09?

A. The essence of Staff's methodology is employing the Differential Revenue Requirement Method described above comparing the present value of the revenue requirements (PVRR) of the base case with one that includes the utility's system including the QF. Items 6 and 7 of the Stipulation state:

> 6. Finally, the present value of the QF project avoided cost is calculated by subtracting the PVRR of the modified plan, with the costs of the QF set to zero, from the PVRR of the base case resource plan.
>
> 7. Rates for capacity and energy from the QF project can then be developed for which, on a present value basis, the expected payments to the QF are equal to the project's avoided cost over the life of the contract.[20]

Note that item 7 states that the avoided cost rate for a QF is found by using both capacity and energy. The end result is that Idaho has two methods for calculating avoided costs, the Proxy method for smaller projects, and the Differential Revenue Requirement Method for larger projects

[20] Direct Testimony of Commission Staff Witness Rick Sterling, IPUC Case No. IPC-E-95-09, Exhibit 101, p. 8.

Q. COULD YOU REVIEW THE "IRP METHOD" PROPOSED BY EACH IOU IN THIS DOCKET?

A. Rocky Mountain Power appears to follow differential revenue requirement method proposed by Staff and approved by the Commission. RMP Company witness Kelcey Brown, in describing that Company's approach, first reviews the seven steps outlined in Staff's "IRP Methodology" and then outlines how the Company follows each of those steps.[21] For the energy component of avoided costs, the Company uses a "GRID" model for two simulations. One using the preferred portfolio, and the second for the QF at no cost that finds the PVRR and then calculates the difference between the two.

Q. HOW DOES RMP FIND THE CAPACITY COMPONENT OF AVOIDED COSTS?

A. To calculate the capacity component of avoided costs, Rocky Mountain Power first determines the level of deferrable capacity measured by the next deferrable CCCT found in its latest IRP, plus the impact of capacity from the requesting QF. Also, when a QF makes a request for avoided cost prices the Company updates the GRID with its latest forecasts for a set of variables they assume have changed since the IRP was filed. According to Ms. Brown:

> The Company updates the GRID model based on the most recently available information each time a QF requests avoided cost pricing. This includes updates related to new contracts, fuel prices, forward price curves, load forecasts and other assumptions. However, the underlying IRP preferred portfolio does not change and is consistent with the most recently filed IRP.[22]

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[21] Direct Testimony of Rocky Mountain Power Witness Kelcey Brown, GNR-E-11-03, pp. 7-10.
[22] Direct Testimony of Commission Staff Witness Rick Sterling, IPUC Case No. IPC-E-95-09, p. 13.

This means the price offered to the QF is calculated on a different basis than what the utility used in the development of their preferred portfolio in their IRP -- which is used to justify the construction of their own resources among other things. In addition, this means the QF requesting a price has the burden of vetting RMP's latest view of loads, fuel prices, and other variables. These "updated" variables have not had even a cursory review by the Commission or stakeholders as have these inputs found in the IRP. In addition, because the outputs of the GRID model run for QFs are being subtracted from the base case with different underlying input assumptions, the results are confounded by whatever changes in these variables the utility assumes have occurred. As discussed above, the IRP's need greater scrutiny if they are to be used for the calculation of avoided cost rates, these unilateral interim adjustments are a step further away from the vetting process and should not be allowed.

Q. DR. READING, WOULD YOU PLEASE COMMENT ON AVISTA'S APROACH TO THE CALCULATION OF AVOIDED COSTS?

A. According to Avista's response to a production request, under the IRP Methodology, assumptions are first reviewed and updated where appropriate (e.g., natural gas, loads and resources). Where assumptions affecting the wholesale marketplace have changed (e.g., natural gas prices) the AURORA IRP model is re-run and Avista's PRiSM model is updated with the new wholesale market data (i.e., value of the new generation resource options). The Company then produces two new PRiSM runs to determine capacity and energy values. In the first new PRiSM run, the capacity component of the QF resource is added to the load and resource tabulation (L&R). The difference between the two economic values (i.e., revenue requirement between the pre-QF PRiSM run and PRiSM run containing the QF capacity) determines the avoided capacity value available for the QF contract. A second PRiSM run is then performed where both the expected capacity and energy contributions of the QF resource are added to loads and resources. The difference between the first PRiSM run and the second PRiSM run determines the energy payments available to the QF contract.

This procedure is somewhat similar to that used by RMP. Loads, natural gas prices, etc. are updated, the QF capacity is added to the resources of the utility and the difference between two PRiSM runs, one with and one without the QF, is calculated to find the avoided cost of energy. As discussed above the input variables that are updated from the IRP by the utility are not subject to any regulatory or stakeholder review and therefore should not be allowed to be used in the calculation of avoided energy costs.

Q. AVISTA IS RECOMMENDING ONE OF THOSE INPUT VARIABLES, NATURAL GAS PRICE, BE UPDATED ANNUALLY FROM RATES PUBLISHED BY THE ENERGY INFORMATION ADMINSTRATION (EIA) IN ITS ANNUAL ENERGY REVIEW. DO YOU AGREE WITH THIS RECOMMENDATION?

A. Yes, because this gas forecast is published by a neutral source on an annual basis and because it is assessable and transparent for all parties. Therefore, for this input from this source it is reasonable to change natural gas prices between the utilities' IRPs. This is consistent with my agreement discussed above with Mr. Kalich's recommendation to use the EIA forecast to annually update published rates in the SAR. Other third party transparent sources for natural gas prices could also be acceptable, so long as a predetermined date is set by the Commission for the update to allow for parity in input changes that will result in rate increases and rate decreases.

Q. COULD YOU NOW DESCRIBE HOW IDAHO POWER IMPLEMENTS THE "IRP METHOD" APPROACH APPROVED BY THE COMMISSION?

A. Yes. Idaho Power recommends abandoning the Commission approved method entirely. It is recommending a peaker method (although it is still being called a modified "IRP Methodology"). The Company is recommending the use of a SCCT rather than a CCCT. In addition, it has abandoned the two model run approach (one with and one without the QF requesting avoided cost pricing), for a single model run method that attempts to replicate the Company's operation of its resource stack during each hour for all hours of the QFs contract term.

Q. COULD YOU PLEASE EXPLAIN IN GREATER DETAIL HOW IDAHO POWER PROPOSES TO DETERMINE THE AVOIDED COST OF ENERGY THAT WILL BE OFFERED TO A QF?

A. Idaho Power is proposing a single run of the AROURA model that calculates avoided energy costs equal to the cost of the Company's most expensive unit forecasted to be on-line for each hour of the year for the contract term. As discussed in the last section, this is estimating avoided cost on a *very* short-run hourly basis. According to the direct testimony of Company witness Karl Bokenkamp:

> Once the highest displaceable incremental cost is identified for a given hour, any amount of displacement available from that resource (generator, longer-term firm purchase or market purchase) sets the incremental cost for that hour regardless of the volume actually available to be displaceable; e. g., if there are no purchases, and all thermal plants are either off or at their minimums except for one Bridger unit which is at 10 MW above minimum and its incremental cost is $17 /MWh even if the "new" QF that the analysis is being run for is expected to produce 20 MW during that hour. This simplification may introduce some error, but it will always be in favor of the QF since Idaho Power begins with the highest incremental cost resource that is displaceable to set the avoided cost for any hour.[23]

However Idaho Power makes another "simplification." This "simplification" of the model run assumes that each of the Company's thermal units has a heat rate equal to its full load operation:

> During many hours of the year, Idaho Power's highest displaceable incremental cost will be set by one of its thermal resources. And because a thermal plant's heat rate changes with load, the incremental costs also change with load. However, to *simplify the analysis*, Idaho Power proposes use of the following assumptions:
>
> 1. Each thermal unit is assigned one incremental cost, which will be based on full load operation, which applies all year long regardless of the loading level determined in the AURORA analysis[.] (*emphasis added*)[24]

The problem with this approach, as Mr. Bokenkamp points out, is that heat rates change as thermal units are ramped up and down. As the generating unit is backed down to follow load its heat rate goes up and its efficiency goes down. Therefore, the cost per MWh of output goes up. Assuming all units in the Company's resource stack are operating at full load, reduces the

23 Direct Testimony of Idaho Power Witness Karl Bokenkamp, GNR-E-11-03, p. 25.
24 *Id.*, p. 24.

avoided cost assumption from how the Company actually operates. According to a Response to a Production Request the \$/MWh difference in incremental energy cost between maximum and minimum load for a unit can be as much as 20%.[25] This process results in an unrealistically low avoided cost rate. In addition, the incremental cost for each thermal unit is updated each year based on the fuel forecasts which, as discussed above, are not subject to any analysis other than the Company's own estimates.

Q. WHAT CONCLUSIONS CAN YOU DRAW FROM YOUR ANALYSIS OF IDAHO POWER'S APPROACH TO CALCULATING AVOIDED ENERGY COSTS THAT WILL BE OFFERED TO A QF?

A. Idaho Power's approach is fatally flawed. As pointed out above, the approach incorrectly assumes avoided costs should be based on a *very* short-run hourly basis. The Company also makes additional "simplifying" assumptions that lower the price that will be offered to a QF. It certainly does not put a PURPA project and the Company's own resources on an equal cost basis. The Company does not, when it wants to build one of its own resources, add that resource to its AURORA model runs, and then ask the Commission for recovery based only on the value of the highest cost resource in the stack in every given hour over the life of the plant. What the Company does is estimate the costs of the resource at a given capacity factor -- which closely approximates the SAR method currently in place.

[25] Idaho Power' Attachment to Response to Exergy's Second Production Request No. 33(b), contained in Exhibit No. 502.

Q. HOW DOES IDAHO POWER RECOMMEND CAPACITY COSTS BE CALCULATED?

A. According to the testimony of the Company's witness:

> The proposed modifications to the IRP-based methodology produce a lower avoided cost of energy for each project. This is expected because the proposed modifications (which are based on identifying the incremental costs to the utility for energy or capacity which, but for the QF purchase, the utility would generate itself or purchase) produce an avoided cost that is based on the incremental cost avoided by displacing one of Idaho Power's thermal generating resources, or avoiding a market purchase. This is in contrast to the current implementation of the IRP methodology which uses the QF output to support market sales or displace purchases which results in a market-based valuation as opposed to a valuation based upon the definition of avoided cost.
>
> The proposed modification to the type of resource used in the avoided cost of capacity calculation results in an avoided cost of capacity that is about 55 percent of that produced by using a CCCT. This is also expected because the capital costs of a SCCT are quite a bit less than the capital costs of a CCCT. The total investment costs for a SCCT and CCCT as identified in Idaho Power's 2011 IRP are $790/KW and $1,380/kW, respectively.[26]

As pointed out above, the Company is proposing to use the "peaker method" in the calculation of avoided costs to be offered to QFs. It should be pointed out once a utility is allowed to put one of their own resources in rate base it will receive full recovery of the capital cost irrespective of whether or not the unit runs. The Company also expresses concerns that ratepayers will get stuck with a PURPA project for a 20 year period without acknowledging that once one of their own

[26] Direct Testimony of Idaho Power Witness Karl Bokenkamp, GNR-E-11-03, p. 32.

plants is placed in rate base that ratepayers will pay the for the capital costs of the facility even if the plant is seldom run.

Q. DR READING DO YOU HAVE ANY CONCLUDING REMARKS ABOUT THE AVOIDED COST PROPOSALS AND THE UTILITIES' "IRP METHODOLOGY " VS THE SAR METHODOLOGY?

A. Yes. All accepted methods (as described above) for calculating avoided costs have pluses and minuses. One of the major pluses for the SAR method is its simplicity and transparent nature. Idaho Power's witness Hieronymus's direct testimony references a report by Ms. Carolyn Elefant. In that report she lists the "Pros" and "Cons" of the various avoided cost methodologies. The "Pro" for the Proxy Method is that it is "Simple and transparent."[27]

One of the problems with what each of the utilities is proposing is that each company uses different models, each of which has thousands of input assumptions and algorithms that neither a requesting QF nor the Commission have the resources to examine thoroughly. On the other hand the SAR methodology has few enough variables that the parties and Commission Staff can analyze and present their case to the Commission as to the reasonableness of the utility's assumptions. The proposals offered by the IOUs put the utilities in the driver's seat for the determination of avoided cost rates offered to potential PURPA projects. Added to this complexity, is the number of variables the utilities propose to make between IRP's (as discussed

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27 Carolyn Elefant, *Reviving PURPA's Purpose: The Limits of Existing State Avoided Cost Ratemaking Methodologies in Supporting Alternative Energy Development and A Proposed Path for Reform*, p. 24.

above) that are changed at the discretion of the utilities and not properly vetted by the Commission or the parties.

Q. DR. READING HAVE YOU LOOKED AT THE RATE IMPACT FOR VARIOUS TYPES OF PROJECTS USING THE PROPOSALS BY THE UTILITIES IN THIS DOCKET?

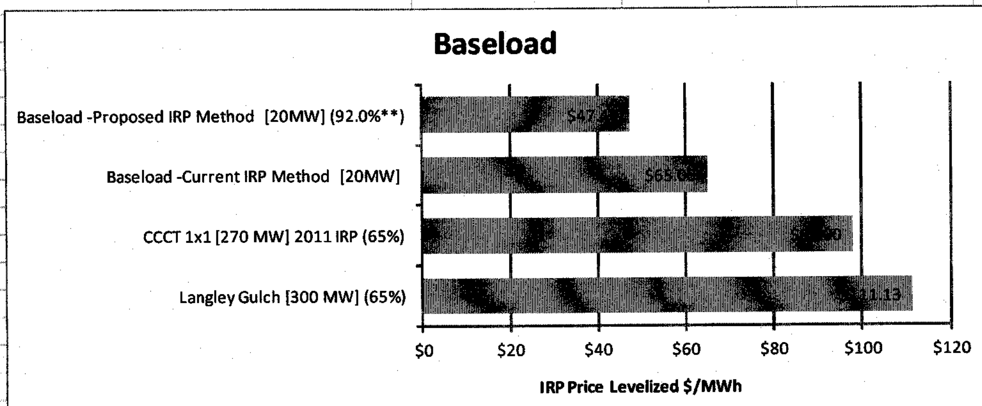
A. Yes. For all types of QF projects modeled for all three utilities the proposed methods have the effect of significantly lowering avoided cost rates from the current posted rates. One of more curious aspects of the utilities' approach is that their proposed avoided cost rates from their "IRP Method" are significantly lower than the costs of building the utilities' own resources, as well as, the costs presented in their recently filed IRPs. This result should not be a surprising given the above discussion about how their proposed method measures only short-run avoided costs and contain updated lower natural gas prices and loads. What is obvious in comparing these rates is that the utilities want to offer QFs significantly lower rates than what they think it costs to build their own generating capacity. These comparisons clearly point out the fallacies in their approach and show the difference between the "avoided costs" of their own resources and what they claim is fair to offer a QF.

Q. COULD YOU BE MORE SPECIFIC AND DEMONSTRATE WHAT YOU MEAN WHEN YOU SAY AVOIDED COSTS ARE SIGNIFICANTLY DIFFERENT BETWEEN WHAT THE UTILITIES BELIEVE IT COSTS THEM TO BUILD A RESOURCE AND THE AVOIDED COSTS PROPOSED TO BE OFFERED TO QFs?

A. I will look at each utility in turn, and start with Idaho Power's calculations. The Company has developed its avoided costs estimates for four hypothetical QFs each with a different motive force. The four types are Baseload, Canal-drop Hydro, Fixed PV, and Wind. The following four Charts depicts each of these four types with the levelized 20 year MWh costs calculated by Idaho Power based on $/MWh basis. The comparison costs in $/MWh for each type are based on the Company's 2011 IRP that was officially noticed by the Commission in December 2011, along with the current and proposed IRP Method avoided cost calculations. For Baseload comparisons Langley-Gulch values are included based on cost estimates filed by Commission Staff.

As can be seen in the following Chart 1, the costs vary between a high of $111.13 per $/MWh for Langley Gulch to a low of $47.40 per $/MWh for the Company's proposed IRP Method. Langley Gulch is included in the baseload comparisons because it is entering the Company's resource stack in June of this year. From a theoretical basis, it can be argued that either the next or last generation plant is an accurate measure of the utility's marginal costs.

Resource Type (Capacity Factor)	Levelized Cost $/MWh	Source
Langley Gulch [300 MW] (65%)	$111.13	Staff Comments, IPC-E-09-34 (Neal Hot Springs), 5/3/2010
CCCT 1x1 [270 MW] 2011 IRP (65%)	$98.00	IPCo 2011 IRP, p. 47; without carbon adder of $10 $/MWh
Baseload -Current IRP Method [20MW]	$65.00	IPCo Memorandum in Support of Stay, p. 15, GNR-E-111-03
Baseload -Proposed IRP Method [20MW] (92.0%*)	$47.40	IPCo Memorandum in Support of Stay, p. 15, GNR-E-111-03



* 90th Percentile Peak-Hour Capacity Factor

While it might be argued each of four cost estimates are not precisely comparable, the order of magnitude of the difference between the utility's baseload load plant currently coming on line, and what it proposes to offer a baseload QFs, is so dramatically different it calls into question the claims that the proposed method is a realistic estimate of the Company's avoided cost. It is also important to note all four of these estimates can be considered falling within the same time frame and are therefore comparable.

Q. DID YOU FIND THE SAME PATTERN OF THE AVOIDED COST PRICE RELATIONSHIHP BETWEEN THE COST OF DIFFERENT TYPES OF GENERATION WHEN YOU REVIEWED RMP AND AVISTA?

A. The costs of various types of generation found in the IRP and the avoided costs proposed to be offered to a QF show, as in the case of Idaho Power, significantly lower proposed avoided costs. For Avista the lowest resource cost found in their IRP is $99.07 $/MWh for a CCCT.[28] With the exception of Hydro at $114.48 per MWh the highest proposed avoided cost offered is $75.30 per MWh for Solar with the lowest being $42.51 for Wind.[29] A similar comparison for Rocky Mountain Power could not be made because matching the resource types between the avoided costs presented in the Company's testimony and its latest IRP did not match up well. However, a general comparison between the five hypothetical types are significantly lower than those numerous resource types presented in RMP's latest IRP.[30] These divergent prices again demonstrate that prices offered to QFs do not match what the utility believes it would cost to build the type of resource and hence is not reasonable to be used as an accurate estimate of avoided cost.

Q. COULD YOU SUMMERIZE YOUR RECOMMENDITIONS BASED ON THE DISCUSSION ABOVE?

A. Published rates should be available for all types of QF projects less than 10 aMW based on the SAR method. I do support Avista's proposal to update published rates utilizing the gas SAR utilizing the EIA's Annual Outlook Report, provided that the Commission sets a predetermined date applicable for the rate change. For projects over 10 aMW, what is called the "IRP Method" should be used only when each utility's IRP is fully considered and approved through the hearing process. Changes to variable inputs in the IRP Methodology should not be

28 Avista Corporation's 2011 Integrated Resource Plan, Chapter 6.
29 Direct Testimony of Avista Witness Clint Kalich, GNR-E-11-03, Table 4, p. 24.
30 Direct Testimony of Rocky Mountain Power Witness Kelcey Brown, GNR-E-11-03,Table A, p. 5; PacifiCorp's 2011 Integrated Resource Plan, Chapter 6.

allowed between approved IRP's with the exception of natural gas prices based on EIA's annual updates or from another publicly available third party source on a predetermined date. The single model run approach advocated by Idaho Power should be rejected, and the models should instead be run twice – once with the QF at zero cost and once without the QF. QF projects should be eligible for capacity payments for the full term of their contract with no deficit period allowed, and a 20 year contract term should remain the standard which is discussed further below.

PART 2: OTHER QF ISSUES

I. LIQUIDATED DAMAGES AND DELAY SECURITY

Q. AVISTA COMPANY WITNESS CLINT KALICH STATES QF CONTRACTS SHOULD CONTAIN A PROVISION WITH "MEANINGFUL" DELAY DEFAULT LIQUIDATED DAMAGES IN HIS DIRECT TESTIMONY. DO YOU HAVE ANY COMMENTS ON HIS DISCUSSION ON PAGES 31 THROUGH 33?

A. Yes. In addition to my comments, I have also included discovery responses by Avista addressing this issue as **Exhibit 503** to my testimony. "Meaningful" of course is another term that is in the eyes of the beholder. Mr. Kalich recommends the Commission authorize utilities to require QFs to post a security deposit equivalent to $45 per kilowatt of nameplate capacity, and allow the utility to terminate the contract and keep the $45 per kilowatt deposit if the actual on line date is more than 180 days beyond that stated in the contract.[31] The rationale for the 180 day termination condition is the Company fears a developer may simply hold off bringing the project on line if prices are falling and waiting for prices to hopefully increase. Mr. Kalich supports the security provision because it creates a meaningful deterrent to delay in achieving the proposed on line date. There are two major issues with what Avista (or any other utility) is proposing for liquidated damages for a QF.

Q. WHAT IS THE FIRST ISSUE?

A. The first issue is that no Idaho utility has provided the Commission with any analysis on a utility's likely actual damages in the event that a PURPA project either did not come on line at the stated contract date or failed to come on line completely. Instead, the $45 per kilowatt delay security amount appears to be an amount that the utilities have decided will provide adequate deterrent to a breach. Avista simply conducted a survey of what other utilities have been able to demand as a delay security in PPAs with independent power developers and states it has not estimated the likely costs to Avista or any other utility should a QF default.[32] This is out of line with Commission orders, which I presume are based upon the Commission's understanding of Idaho contact law.

With regard to a recent contract containing a delay liquidated damage security, the Commission stated "the Commission is concerned that such provisions will have a potentially deleterious effect upon future PURPA projects. Quite often, operators of qualified small power

[31] Direct Testimony of Avista Witness Clint Kalich, GNR-E-11-03, pp. 32-33.
[32] Avista Response to Clearwater Paper's Production Request Nos. 11, 13, and 14, contained in Exhibit 503.

production facilities do not have ready access to the necessary amount of security or capital delineated in this Agreement."[33] The Commission declared:

> Therefore, the Commission finds that such provisions calling for delay security should not be punitive in nature. Rather, the amount of delay security ultimately provided in this case, as well as future energy sales agreements with other PURPA suppliers, should constitute a fair and reasonable offset of a regulated utility's estimated increase in power supply costs attributable to the PURPA supplier's failure to meet its contractually scheduled operation date.[34]

In other words, a liquidated damages provision should not operate merely as a one-way penalty to deter one party from breaching the agreement. It should not be derived from a canvassing of terms required by other utility purchasers because the traditional utility market is essentially a monopsony market with only very limited number of purchasers in the region of any independent power project. Standard terms in such a monopsony market place should not be assumed to be fair. Instead, the liquidated damage provision should be an actual estimate of the likely damages the non-breaching party (here, the utility) would incur. The intent should be to keep the utility and its customer's whole in the event of a default. Otherwise, the provision is simply a penalty provision unilaterally imposed by the party with superior bargaining strength. Avista has admitted that it has made no effort to approximate its likely actual damages in the event of a QF delay default.[35]

Q. HOW WOULD YOU ESTIMATE A UTILITY'S ACTUAL DAMAGES IN THE

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33 IPUC Order No. 30608, p. 3, Case No. IPC-E-08-09 (2008).

34 *Id.*, p. 4.

35 Avista Response to Clearwater Paper's Production Request No. 13, contained in Exhibit 503.

EVENT OF A QF'S DELAY DEFAULT?

A. One easy way to estimate a purchasing utility's actual damages in the event of a QF delay default is to require the QF to pay the difference between the rate the utility would pay in the QF contract and the actual cost for replacement power during the period the QF's delay default forces the utility to secure replacement power. The replacement price would include the cost at the relevant market hub plus the necessary transmission and administrative costs to secure that replacement power. The period during which the utility would need to secure replacement power should not last for the entire term of the power purchase agreement, which could be up to twenty years, because the utility could obviously make alterative arrangements to meet its load needs prior to the expiration of the 20-year contract term. The period during which the breaching QF should be liable should be limited to a reasonable amount of time for the utility to make alternative long-term arrangements to secure that amount of power. I understand that Idaho QF power purchase agreements have in the past contained provisions tied to the replacement price of electricity and capacity. The market price for replacement power in the event of a QF default is quite low at the present time, and $45 per kilowatt is an excessive amount for a QF to automatically forfeit in the event of a delay. For example, at $45 per kilowatt, a 10 MW QF must provide $450,000 to the utility at the time the contract is approved. Under Mr. Kalich's proposal, the utility would receive $450,000 for a 180 day delay in a QF's achievement of its committed on line date. This appears far in excess of the utility's actual cost for replacement power at the present time.

It is only in the last few years that the utilities began unilaterally imposing the $45 per kilowatt delay security liquidated damages provision for QF contracts. Although I am aware of complaint cases where QFs have alleged that a $45 per kilowatt delay damage provision is unfair, I am not aware of any QFs having fully litigating such a complaint at the Commission.[36] The Commission should not consider the absence of a fully litigated challenge to be representative of a belief that these clauses are a fair estimation of the utility's actual damages, as required by the Commission order cited above. Even for a QF with the financial resources to litigate the legality of the clause, a delay caused by filing a complaint at the Commission could compromise the viability of the entire project because the timing of tax credits, financing and equipment supplies are critical in development of a generation project.

Mr. Kalich even recommends requiring the $45 per kilowatt security amount be provided by the QF simply to exercise the QF's right to create a legally enforceable obligation, i.e. a binding contract that would lock in the fixed avoided cost rates. Many QFs cannot secure financing and access to such large amounts of money until after the PPA is signed and approved by the Commission. Thus, Mr. Kalich's proposal would create a timing problem for many QFs, and would obviously be a substantial hurdle for all but the most well-funded QFs.

For all of these reasons, if such a requirement is to be authorized by the Commission, it should not be based on a flawed method of calculating the utility's actual damages, so as to unnecessarily deter otherwise viable QF projects. The Commission should take the opportunity

[36] See IPUC Case Nos. IPC-E-10-29 and -30; PAC-E-10-05.

in this case to require the utilities to tie the delay default provision to a utility's actual damages.,

Q. WHAT IS THE SECOND ISSUE YOU WOULD LIKE TO MENTION WITH DELAY SECURITY AND LIQUIDATED DAMAGES PROVISIONS?

A. Mr. Kalich notes in his testimony that the Company wants to "ensure a level playing field" between the QF and the utility.[37] A true level playing field would be where the utility-owned plants must be held to the same standard and issue rate payer refunds when their own plants experience failures or delays. A good example is Avista's Reardan wind project that was in the utility's Preferred Resource Strategy in its 2009 IRP. It was slated to come on line in 2010 or 2011, but now is not scheduled until 2014 or beyond. This is not to say that Avista necessarily acted irrationally to replace this project with the Palouse wind RFP. I simply intend to point out that utilities regularly incur expenditures for generation plants that either never come on line or are delayed. If there are real costs to a utility and its customers that warrant a delay default provision in a QF PPA, then there should likewise be compensation to the utility's customers for a similar delay occurring at a utility-owned generation project. Avista's proposal provides for unfair treatment to QFs and deprives the utilities' customers of a comparable market check to the utilities' proposals to build their own generation resources.

Q. IS THERE ANYTHING ELSE THAT WOULD LEVEL THE PLAYING FIELD?

A. Yes, Mr. Kalich proposes only a provision that would address a default by the QF. But there is the possibility that the QF could be harmed by a utility under certain circumstances, and

37 Direct Testimony of Avista Witness Clint Kalich, GNR-E-11-03, p. 33.

therefore QF contracts should provide for compensation to the QF in the event of a utility default. For example, a delay in achieving an on line date could occur solely because the utility failed to complete interconnection construction as scheduled. The QF could be damaged by such a delay because it could delay the project's schedule and the time by which the project would start generating revenue. Such a delay by the utility in completing interconnection should not result in the QF being in default on its power purchase agreement. Another potential cause of damage to a QF is if the utility experiences a disruption on its system that requires curtailment of the QF for a lengthy period of time. The QF should be compensated for the lost revenue and other damages it might incur by the unscheduled outage. Further, as I will discuss below, Idaho Power's proposed Schedule 74 curtailment provision would allow Idaho Power to curtail QFs under certain circumstances. But Idaho Power's provision provides no express remedy to QFs if Idaho Power implements the curtailment at an inappropriate time or in a manner that harms the QF.

If Idaho QF PPAs will include damage provisions, they should address the possible damages to the QFs also, not just the potential damages to the utilities.

II. AVISTA'S PROPOSAL THAT QFs MUST ACHIEVE ON LINE STATUS WITHIN 2 YEARS TO OBTAIN FIXED RATES.

Q. DO YOU HAVE ANY COMMENTS ON AVISTA COMPANY WITNESS KALICH'S RECOMMENDATION THAT QF CONTRACTS NOT BE SIGNED EARLIER THAN FIVE YEARS BEFORE COMMERCIAL OPERATION AND THAT

FIXED PRICES SHOULD BE MADE AVAILABLE NO EARLIER THAN TWO YEARS BEFORE COMMERCIAL OPERATION?

A. Yes. A QF that is building a new project will need to secure financing before commencing construction. A bank or lender is unlikely to agree to provide the money to build the project until there is a guaranteed revenue stream if the project is successfully built. Mr. Kalich's proposal essentially would give a new QF a maximum of two years after signing the PPA within which to secure financing, and achieve on line status. For many types of generation projects, it could take much longer than two years to complete construction alone. Mr. Kalich's testimony contains no analysis of the impact of this 2-year requirement on a party attempting to build a generation project. If adopted, the requirement would certainly deter some QF projects.

Q. WHAT IS MR. KALICH'S REASONING FOR THIS 2-YEAR REQUIREMENT?

A. Mr. Kalich states: "Too many things affecting price can change over a five-year term, both for the QF developer and the utility."[38] Apparently, Avista's concern is that the avoided costs may decrease between the time of contract execution and the time the QF project is built. This is another example of the utilities attempting to require QFs to provide greater assurances to ratepayers than the utilities themselves would ever agree to provide.

Q. PLEASE EXPLAIN.

A. While the Company recommends this 2-year condition for a QF, the condition is demonstrably inapplicable for a utility-built plant. Idaho Power received its CPCN with the

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[38] Direct Testimony of Avista Witness Clint Kalich, GNR-E-11-03, p. 31.

costs approved for Langley Gulch in September of 2009 but will not be on line until June of 2012. It is interesting to apply both Mr. Kalich's delay security provision proposal and his 2-year on line status proposal to the Langley Gulch plant. For Langley Gulch to receive guaranteed fixed rates, Mr. Kalich's proposal would require it to provide a guaranteed on line date within two years of September 2009 when the Commission issued the CPCN. To obtain guaranteed rate recovery for the estimated capital costs of the plant (which the Commission essentially granted subject to a price cap in IPC-E-09-03), a Langley Gulch QF would have to agree to an on line date no later than September 2011. Mr. Kalich would require a QF to post $45 per kilowatt. For the 330 MW Langley Gulch plant approved in Order No. 30892, Idaho Power would have had to post $14.8 million in September 2009 as a guarantee it would be on line by September 2011. Mr. Kalich's delay default proposal would allow termination of the QF if it were not on line within 180 days of the proposed on line date. A "Langley Gulch QF" would forfeit its $14.8 million security if not on line by March 2012. Langley Gulch is still not on line today in May 2012, and is not even scheduled to be on line until at least June 2012. Its approval could therefore be terminated.

If the Commission were to apply Mr. Kalich's proposal for QFs to the Langley Gulch project, ratepayers could terminate the approval of the plant today and walk away from the project altogether for any reason. If Langley Gulch were no longer needed because loads had not materialized as predicted by Idaho Power, or if a less expensive offer materialized in the interim, the Commission and the ratepayers could walk away from project, and Idaho Power's shareholders would be responsible for any sunk costs. The prudence of Idaho Power's decision in 2009 would be completely irrelevant once it went beyond the 2-year and 180 day period to achieve on line status. This is not such a hypothetical situation because Idaho Power's load needs are currently less than it projected when it sought approval of Langley Gulch in 2009.

Q. ARE THERE ANY OTHER RECENT EXAMPLES OF UTILITY PLANTS TAKING LONGER THAN TWO YEARS TO ACHIEVE ON LINE STATUS?

A. Yes. In the case of Avista's proposed Reardan wind project, the Commission allowed Construction Work in Progress (CWIP) and Accounting for Funds Used During Construction (AFUDC) for the facility when the land was purchased in 2008.[39] This treatment covered the costs associated with the wind generation site land, land rights, reservation costs, and other incremental costs associated with site evaluation, selection and acquisition to be accounted for as construction work in progress. In its application requesting this preferential ratemaking treatment, Avista represented that it intended for the project to be on line in 2011. To date, Reardan is not on line. As pointed out above should the Reardan project ever be build, the utility would request rate recovery for these costs that are on the Company's books and accruing interest. The utility was able to obtain preferential accounting treatment that a QF would never get, and provided no meaningful guarantees to ratepayers in exchange.

These two examples demonstrate that it is not at all out of the ordinary for it to take more than two years from Commission-approval to bring a utility-owned generation project on line. I

39 IPUC Order 30611, Case No. AVU-E-08-04 (2008).

recommend that the Commission reject this unfair 2-year requirement. If the Commission finds that a 2-year requirement is needed for QF projects to protect ratepayers, the same requirement must also be imposed and enforced for utility-built projects.

III. IDAHO POWER'S PROPOSAL FOR 5 YEAR CONTRACT TERMS

Q. DO YOU HAVE ANY COMMENTS ON IDAHO POWER'S RECOMMENDATION THAT THE STANDARD TERM OF A QF CONTRACT BE REDUCED FROM THE CURRENT TWENTY YEARS TO FIVE YEARS?

A. Limiting PURPA contract terms to five years would preclude the vast majority of QF developers from being able to secure financing for their projects. FERC rules, in 18 C.F.R. § 292.304(b)(5), (d)(2)(ii), allow a QF to lock in long term rates for the term of a contract or legally enforceable obligation with estimated avoided costs calculated at the time the obligation is incurred. In establishing this option, FERC stated:

> Paragraphs (b)(5) and (d) are intended to reconcile the requirement that the rates for purchases equal the utilities' avoided cost with the need for qualifying facilities to be able to enter into contractual commitments based, by necessity, on estimates of future avoided costs. Some of the comments received regarding this section stated that, if the avoided cost of energy at the time it is supplied is less than the price provided in the contract or obligation, the purchasing utility would be required to pay a rate for purchases that would subsidize the qualifying facility at the expense of the utility's other ratepayers.
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> * * * *
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> Many commenters have stressed the need for certainty with regard to return on investment in new technologies. The Commission agrees with these latter arguments, and believes that, in the long run, "overestimations" and "underestimations" of avoided costs will balance out.
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> * * * *

> Paragraph (b)(5) addresses the situation in which a qualifying facility has entered into a contract with an electric utility, or where the qualifying facility has agreed to obligate itself to deliver at a future date energy and capacity to the electric utility. The import of this section is to ensure that a qualifying facility which has obtained the certainty of an arrangement is not deprived of the benefits of its commitment as a result of changed circumstances.[40]

FERC intended to provide a framework within which QFs would be able to obtain financing. FERC provided for rates "to deliver at a future date," and agreed with commenters who suggested there was a "need for certainty with regard to return on investment in new technologies." No utility-owned generation resource will be paid off within five years, and a five-year term cannot provide certainty on the return on investment.

Q. DID IDAHO POWER PROVIDE ANY BASIS FOR ITS PROPOSED 5-YEAR CONTRACT TERM LIMIT?

A. Company witness Mark Stokes rationalizes this proposed reduction in term as a measure to protect customers. Mr. Stokes testified:

> Finally, in order to limit the risk customers are exposed to through longer-term contracts, Idaho Power urges the Commission to reduce the standard contract term from 20 years to five years. Idaho Power believes all of these proposed changes will resolve several problems that exist with the current implementation of PURPA in the state of Idaho, and protect utility customers from further harm.[41]

Mr. Stokes's reasoning sounds much like that of the rejected comments in the FERC rulemaking cited above. The Company's proposal is at odds with the intent of FERC, and would discourage QF development.

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[40] 45 Federal Register 12,214, 12,224 (1980).
[41] Direct Testimony of Idaho Power Witness Mark Stokes, GNR-E-11-03, p. 47.

Q. DO YOU HAVE ANY OTHER COMMENTS ON THE PROPOSED 5-YEAR CONTRACT TERM?

A. Yes. As discussed above in the Section dealing with the IRP methodology, when the utility receives rate base treatment for one of its own generation facilities, the utility commits its ratepayers to reimbursing the utility for its costs for the depreciated life of the project. The capital cost recovery is guaranteed through rate base treatment and the majority of energy costs are recovered annually through an annual power cost adjustment mechanism. Unlike a QF project, those energy costs are not fixed and can go up dramatically from year to year. For example, the price to supply Idaho Power's and PacifiCorp's jointly owned Bridger Coal Plant increased significantly in 2010, and that cost increase was passed on directly to ratepayers.[42] Utility customers are subject to fuel cost risks for utility-owned resources, but are protected from the volatility of natural gas and coal prices when a fixed term QF contract is signed. I am certain Idaho Power would not have been willing to build Langley Gulch if was assured of rate recovery at a set rate for only a five year term rather than for the life of the project. This is yet another example where the utilities propose that the Commission deprive QFs of similar treatment to the utility's own generation resources.

IV. IDAHO POWER'S CURTAILMENT PROVISIONS

Q. DO YOU HAVE ANY COMMENTS ON IDAHO POWER'S PROPOSAL TO

[42] IPUC Order No. 31093, at pp. 13-14, Case No. IPC-E-10-12 (2010). The increased annual cost for Bridger's coal was $24.8 million in 2010 to Idaho Power customers alone. *Idaho Power's Application,* ¶ 24, Case No. IPC-E-10-12.

IMPLEMENT AN ECONOMIC CURTAILMENT TARIFF APPLICABLE TO EXISTING AND NEW QFS, WHICH IS ITS PROPOSED SCHEDULE 74?

A. Yes. In addition to my testimony below, I have attached as **Exhibit 504** to my testimony several discovery responses produced to date by the Company on the topic, and **Exhibit 505**, which is a recent decision by the Montana Public Service Commission rejecting an economic curtailment proposal by NorthWestern Energy for new QF contracts.

Idaho Power already possesses the right through its existing Schedule 72 to curtail QFs for operational concerns to protect system reliability. In this case, the Company proposes to implement economic curtailment of QFs under a proposed Schedule 74. Company witness Tessia Park explains why she believes a FERC rule, 18 C.F.R. § 292.304(f), allows for the Commission to approve the Company's proposal, even for existing QFs with long-term contracts with fixed avoided cost rates and existing curtailment provisions. Ms. Park explains that she believes the federal regulation and associated orders allow that "utilities may curtail higher cost QF energy if the utility would have to dispatch less efficient, higher cost units (other than base load units) to meet system load."[43]

In general, Ms. Park advocates for the right to curtail QFs during certain light loading periods so as to avoid uneconomic operation at several Company-owned facilities that the Company characterizes as "base load." The proposed Schedule 74 tariff attached to Ms. Park's testimony includes the following as "base load" resources: Company-owned hydroelectric

[43] Direct Testimony of Idaho Power Witness Tessia Park, GNR-E-11-03, p. 18.

resources, including all run-of-river generators and the Hells Canyon Complex, coal-fired generating resources (Jim Bridger generating plant, Valmy generating plant, and the Boardman generating plant), and the Langley Gulch power plant.[44]

Q. DO YOU HAVE ANY COMMENTS ON THE COMPANY'S PROPOSAL?

A. Yes. First, I am not an attorney, so I will not provide a legal opinion. However, it strikes me as out of the ordinary to reach back in time to revise existing contracts. QFs have built and secured financing of their projects based on assurance that the contractual provisions would be honored by Idaho Power.

Also, Idaho Power appears to take issue primarily with intermittent QFs in its testimony. But the issue identified by Idaho Power is already addressed in the existing contracts through a wind integration charge. The Commission approved a wind integration charge for Idaho Power, which reduces the otherwise available avoided cost rates for wind QFs and was developed through a lengthy process, and ultimately a settlement of a contested case, to compensate the Company and its customers for the estimated costs of wind integration. The wind integration charge was a component of the estimate of future avoided costs at the time of contracting.

Ms. Park's attempts to explain why the Company's proposed curtailment provision addresses different circumstances from the wind integration charge is not very convincing. In response to the question of whether the $6.50 per MWh wind integration charge covers the cost of balancing services, she testifies: "Partially. As an initial matter, it is important to point out

[44] *Id.*, Exhibit No. 5, p. 1.

that the $6.50 wind integration charge was the result of a negotiated settlement and is not reflective of the Company's actual integration costs."[45] Idaho Power appears to take the position that it can change the terms of its prior settlement agreement which has now been incorporated into the avoided cost rates in many QF contracts. Idaho Power appears to believe that the "actual" wind integration charges are different from those set forth in the existing PPAs, and therefore an additional economic curtailment provision is necessary to make up the difference.

If the wind integration charge of $6.50 per MWh in existing contracts were found by the Commission to be in excess of Idaho Power's actual wind integration costs, I doubt that Idaho Power would agree (or the Commission would require it) to adjust the avoided cost rates in those contracts upwards. The same is true of any other component of the avoided cost rates. The avoided costs and all components thereto are estimates of actual avoided costs, which could be higher or lower than actual projected costs. It does not appear fair to me for Idaho Power to try to essentially impose additional wind integration charges through an economic curtailment provision, any more than it would be fair for Idaho Power revise the avoided cost rates in any other manner in any existing QF contract.

Q. DOES THE COMPANY'S PROPOSAL APPEAR TO DESCRIBE A SITUATION SIMILAR TO THAT DESCRIBED IN THE FERC ORDERS THE COMPANY CITES?

A. I do not believe so. In developing 18 C.F.R. § 292.304(f), FERC stated:

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[45] *Id.*, p. 13.

> This section was intended to deal with a certain condition which can occur during light loading periods. If a utility operating only base load units during these periods were forced to cut back output from the units in order to accommodate purchases from qualifying facilities, these base load units might not be able to increase their output level rapidly when the system demand later increased. As a result, the utility would be required to utilize less efficient, higher cost units with faster start-up to meet the demand that would have been supplied by the less expensive base load unit had it been permitted to operate at a constant output.[46]

This language discusses a circumstance where a utility that operates only slow-ramping base load facilities, such as a coal plants, would have to be back down those units during light loading periods to accept QF output, but could not then start those units back up quickly enough to meet the utility's next peak. The FERC regulation would apply if the utility had to instead meet the next peak with a more expensive peaking resource, such as a less efficient gas peaking unit. This does not appear to apply to Idaho Power for several reasons.

Idaho Power does not meet its load solely with slow-ramping base load coal plants. It also meets its load with its hydroelectric plants and will soon meet load with its Langley Gulch Plant, which it specifically described at the time of its request for its CPCN as being useful for wind integration.

Q. HAS IDAHO POWER ADEQUATELY DEMONSTRATED THAT ITS SYSTEM CONFIGURATION IS SIMILAR TO THE SCENARIO CONTEMPLATED BY THE FERC RULE?

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[46] 45 Federal Register 12,214, 12,227 (1980).

A. No. The Company's discovery responses have not demonstrated that the circumstance described by FERC would ever exist for Idaho Power. The Company's whole proposal hinges on Idaho Power's position that it has a certain level of "must-run" generation, which cannot be scaled back to accept the QF output it is contractually obligated to accept and buy when it is provided. According to the Company, it must therefore curtail QFs.

Specifically, the Company lists the following resources as having the following "must-run" output during typical low loading times of the year: Hells Canyon Complex (no less than 350 MW), Mid-Snake "run-of-river" hydroelectric projects (450 MW), the Bridger and Boardman thermal units "that are 'in the money'" (300 MW), and non-intermittent PURPA generation (50 MW).[47] That totals 1150 MW. Ms. Park testifies: "If Idaho Power were to cycle off its thermal units in the middle of the night to accommodate PURPA generation, the Company would need to start up its higher cost, less efficient natural gas peaking units or make more expensive market purchases (assuming transmission would be available) to meet system load during heavy load hours during the next day."[48] There are several gaps in Idaho Power's logic.

Q. WHAT ARE THE GAPS IN IDAHO POWER'S LOGIC?

A. First of all, FERC's description does not state that curtailments would occur when the QF purchases may cause the utility to enter into more expensive market purchases; it refers to operational circumstances at specific utility plants.

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[47] Direct Testimony of Idaho Power Witness Tessia Park, GNR-E-11-03, pp. 23-24.
[48] *Id.*, pp. 24-25.

Second, Ms. Park appears to state that its coal plants can be taken off-line and brought back on line provided that Idaho Power gives the plant's operating utility up to one week notice.[49] Thus, if Idaho Power can go a week without needing its coal plants during these light loading periods, it appears to have no need to have them on line to begin with for operational purposes. Idaho Power seems to suggest that it typically has such large load swings day-to-day during these light loading times of the year that it must keep its Bridger and Boardman coal plants on line to meet its peak loads during these times of the year. The actual load swings within the weeks following light loading events of less than 1100 MW in the years 2010 to 2011 are contained in Idaho Power's Response to Exergy Production Request No. 22, contained in my Exhibit 504. Although I am not an operations expert, it does not appear to me that Idaho Power has fully considered whether it would really need to run gas peakers if it were to take more units at the coal plants off-line during weeks where it expected a light loading event. Without the full 300 MW of minimum generation coal on line, as Idaho Power assumes there must be, there is a reduced need to curtail QFs during a minimum loading event.

Another problem with Idaho Power's analysis is that it assumes it must run and accept output from its run-of-river hydroelectric projects, and must curtail existing QFs to do so during light loading periods. Idaho Power takes the position that this 450 MW of generation cannot be taken offline to accommodate QF deliveries. However, Idaho Power stated in discovery that it has the operational capability to run water through those projects (or spill it) without generating

49 Direct Testimony of Idaho Power Witness Tessia Park, GNR-E-11-03, p. 22.

electricity.[50] Idaho Power has not asserted that the FERC licenses prohibit it from taking the plants offline in order to accommodate system reliability concerns such as a light loading event where it has excess generation. Nor has Idaho Power asserted that the plants cannot be brought back on line quickly if QF generation were to drop off or loads were to pick up.

Q. ARE THERE ANY OTHER FLAWS IN THE LOGIC OF IDAHO POWER'S PERCEIVED RIGHT TO ECONOMIC CURTAILMENT?

A. Yes. Idaho Power appears to assume that it must keep the Bridger and Boardman Coal plants on line during these periods where it experiences light loading. Its statement that it cannot take coal plants offline is inconsistent with its statement that it does in fact take Valmy offline during these periods "because of its relatively high dispatch cost and because it is not needed to serve load during these low load times of year."[51] Idaho Power appears able to take its coal plants offline when it chooses to do so for its own reasons. Idaho Power appears to be predetermining that certain coal plants will be "in the money" and therefore are "must run" during a light loading event, even if running the coal plants to facilitate off-system sales means Idaho Power must curtail QFs for general economic purposes. Idaho Power will soon have Langley Gulch on line, and part of Idaho Power's justification to the Commission for that plant was that it would be useful for integrating wind. It is not clear why Langley Gulch, the Hells Canyon, and Mid-Snake hydroelectric projects, supplemented by occasional market purchases, cannot be used to integrate wind during these light loading periods.

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50 Idaho Power Response to Exergy Production Request No. 19, contained in Exhibit 504.
51 Direct Testimony of Idaho Power Witness Tessia Park, GNR-E-11-03, p. 23, note 1.

Q. WOULD IDAHO POWER'S PROPOSAL APPLY TO ALL QFS?

A. No. Idaho Power has only requested that the proposal apply to any QFs over 10 MW with a generator limiting device Idaho Power can use remotely (regardless of resource type). Although Idaho Power designated the list of such QFs to be confidential, one can conclude from the testimony that it would only affect more recently built QFs, for the time being. However, it is also apparent that Idaho Power's economic curtailment provision would not apply to the four QF projects owned by Idaho Power.

Q. DID YOU SAY IDAHO POWER OWNS QF PROJECTS THAT SELL TO IDAHO POWER?

A. Yes. Idaho Power is a 50% owner, through a subsidiary named Ida-West Energy, of four hydroelectric projects that sell QF output to Idaho Power. Those projects are South Forks (8.2 MW), Hazelton B (7.7 MW), Wilson Lake (8.4 MW), and Falls River (9.1 MW). Idaho Power's QFs are all under 10 MW, and therefore Idaho Power's QF projects would not be subject to Idaho Power's economic curtailment tariff that applies to other QFs.

Q. DO YOU HAVE ANY OTHER COMMENTS ON THE CURTAILMENT PROPOSAL?

A. Yes. Idaho Power provided the Commission with state utility commission orders from Nevada and Florida implementing FERC's curtailment rule. I am aware of a more recent state commission order addressing this curtailment issue. Just last year, the Montana Public Service Commission rejected a request by NorthWestern Energy to prospectively include an economic curtailment provision in future QF contracts. That decision is attached as **Exhibit 505**. The Montana Commission found that the FERC regulation allowed for curtailment only in very limited circumstances. The Montana Commission stated: "If market conditions occasionally result in prices less than NWE's tariffed avoided costs, that is not in itself a sign that the principle of consumer indifference is unlawfully being violated—no more than if a long-term acquisition of NWE's own were to result in a fixed-and-variable cost-per-unit which were higher than prices available on the spot market."[52]

That order also cited to the Montana regulation on the subject, which states: "Failure to properly notify the qualifying facilities and the commission or incorrect identification of such a period will result in reimbursement to the qualifying facility by the utility in an amount equal to that amount due had the qualifying facility's production been purchased."[53] This is consistent with FERC's description of its own provision, which stated: "any electric utility which fails to provide adequate notice or which incorrectly identifies such a period will be required to reimburse the qualifying facility, for energy or capacity supplied as if such a light loading period had not occurred."[54] In contrast, Idaho Power does not propose any provision whereby it would be required to compensate QFs for inadequate notice, or for an improperly implemented curtailment.

[52] Montana PSC Order No. 7172, ¶ 12, contained in Exhibit 505.
[53] *Id.*, ¶ 6 (citing Montana Administrative Rule § 38.5.1903(1)).
[54] 45 Federal Register 12,214, 12,228 (1980).

The Commission may find this more-recent Montana order addressing a proposal for new QF contracts useful in evaluating Idaho Power's proposal for existing QF contracts.

Q. DO YOU HAVE ANY CONCLUDING REMARKS ON THE CURTAILMENT ISSUES?

A. Idaho Power acknowledges that it already possesses a tariff that allows for curtailment for system integrity purposes, Schedule 72. Existing QFs agreed to circumstances under which Idaho Power could curtail them for operational purposes when they decided to proceed with building and operating their QF projects. I will let the lawyers debate the legality of unilaterally amending contracts. However, I believe Idaho Power's proposal to alter the settled relationships in PPAs would not be a policy that would encourage QF development. I am not convinced Idaho Power meets FERC's criteria for limited operational curtailment, even for new QF projects. I recommend that the Commission not approve Idaho Power's proposed economic curtailment for any QFs.

V. OWNERSHIP OF ENVIRONMENTAL ATTRIBUTES

Q. DO YOU HAVE ANY COMMENTS ON OWNERSHIP OF ENVIRONMENTAL ATTRIBUTES?

A. I have very limited comments on ownership of environmental attributes, and have included **Exhibit 506** which contains a discovery response on the topic. Idaho utilities have attempted at least twice to obtain a Commission order declaring the utility the owner of environmental attributes in Idaho QF contracts.[55] The Commission has never allowed the utilities to insist on such a provision, and Idaho Power affirmatively disclaimed ownership in its QF PPAs until recently. Some Idaho utilities have recently begun insisting on a contract provision that clouds a QF's title to the environmental attributes by declaring ownership to be governed by controlling law as it may exist at some future time during the term of the agreement. This unilateral insistence on a term that QFs disagree with is a good example, like the delay security issue addressed above, of an issue the Commission should resolve to provide predictability in the QF market place. Idaho Power has described in a discovery response in this case how it has been able to obtain certain QFs' agreement in last year to give Idaho Power some of the QFs environmental attributes for no additional compensation, after Idaho Power first insisted on a contract clause that clouded the QF's title to the environmental attributes.[56]

Only Rocky Mountain Power witness Paul Clements has proposed to address ownership of environmental attributes in this case.[57] He believes that the utilities should own the environmental attributes without providing any additional compensation to the QF over and above the avoided costs of energy and capacity. Neither Idaho Power nor Avista requested any specific order on the issue in this docket.

Q. WHAT IS YOUR OPINION DR. READING?

A. In my opinion, insisting on utility ownership of RECs or insisting on a PPA clause

55 IPUC Case No. IPC-E-04-2; IPUC Case No. AVU-E-09-04.
56 Idaho Power Response to Exergy Production Request No. 2, contained in Exhibit 506.
57 Direct Testimony of Rocky Mountain Power Witness Paul Clements, GNR-E-11-03, pp. 7-10.

clouding a QF's title and is not fair. The avoided costs in Idaho compensate QFs only for the energy and the capacity provided. It appears the utilities' are making every effort in this case to keep the compensation to QFs as low as possible. To also assert that the utility owns the non-energy attributes of QF generation without any additional compensation is unreasonable. The legal issues regarding ownership of environmental attributes are currently being litigated in another docket, and I understand that it has been fully submitted with legal briefing for a few months now.[58] I recommend that the Commission resolve this dispute as soon as possible by requiring the utilities to disclaim ownership of the environmental attributes for which they refuse to compensate QFs.

VI. QF CONTRACTING PROCESS TARIFF

Q. DO YOU HAVE ANY COMMENTS ON ROCKY MOUNTAIN POWER'S AND IDAHO POWER'S PROPOSALS THAT THE COMMISSION ADOPT A TARIFF THAT WOULD ESTABLISH A CONTRACTING PROCESS?

A. Yes. Both utilities have expressed support for a contracting tariff so far in this case, but only Rocky Mountain Power has actually proposed a specific tariff. Rocky Mountain Power witness Paul Clements provided a proposed Schedule 38 for non-standard QF contracts, which he states is based on tariffs used in Wyoming and Utah.[59] Idaho Power witness Mark Stokes expressed the Company's support for a contracting tariff, but he provided no specific tariff upon

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[58] IPUC Case No. IPC-E-11-15.

[59] Direct Testimony of Rocky Mountain Power Witness Paul Clements, GNR-E-11-03, pp. 2-7 and Exhibit 202.

which any party can comment. The Company stated in discovery that it thought providing a tariff with its initial filing would be premature. That is of course entirely inconsistent with its submittal of a curtailment tariff proposed as its Schedule 74.

Q. DO YOU BELIEVE THAT A QF CONTRACTING TARIFF WOULD BE USEFUL?

A. Yes, but only if the process is designed to prevent a utility from imposing unnecessary delays in negotiations and only if the tariff requires meaningful deadlines with which the utility must comply. Rocky Mountain Power's tariff fails on both of these requirements.

Q. WHAT ARE THE PROBLEMS WITH ROCKY MOUNTAIN POWER'S PROPOSED TARIFF?

A. First of all, it only addresses a contracting process for non-standard QFs seeking individually calculated avoided cost rates, and therefore provides no assurance that any particular process will be followed for small QFs seeking published rates and standard contract terms.

Second, as Mr. Clements acknowledges, the deadlines for the utility to respond to QF requests are far longer than deadlines authorized by the other states' tariff from which Mr. Clements supposedly developed the proposed Idaho tariff. Specifically, Mr. Clements proposes a 45-day response period for the utility to provide a draft contract after indicative pricing is provided and all required information is submitted by the QF. This is an unnecessary and excessive delay in the negotiating process. It is very difficult to believe that a sophisticated utility like PacifiCorp cannot easily complete what should be a standard draft contract within a shorter timeframe than 45 days.

Q. DO YOU HAVE AN ALTERNATIVE PROPOSAL?

A. I propose using the standard contracting tariffs approved by the Public Utility Commission of Oregon. These tariffs were developed in a fully litigated proceeding (Oregon Commission Docket No. UM 1129), not by a utility's own efforts to improve the tariffs of another commission. Both Rocky Mountain Power (operating as PacifiCorp doing business as Pacific Power and Light in Oregon) and Idaho Power already have experience using these standard contracting procedures. PacifiCorp's Oregon Schedule 37 for standard QF contracts and Schedule 38 for large QF contracts are both available on line.[60] Idaho Power's Oregon Schedule 85, which addresses both standard and non-standard contracting practices, is also available on line.[61]

The Oregon tariffs for small QFs include a reasonable list of required information the QF must provide to obtain a draft PPA, and require the utility to respond to QF inquiries within 15 business days. For large QFs, the utility must respond to inquiries within 30 days, and must provide a final contract within 15 business days of agreement to all terms. This is a more reasonable turn-around time than the 45 days proposed by Rocky Mountain Power. Each tariff also includes a standard tariff contract for small QFs to limit the need to engage in protracted negotiations for small QFs. The Oregon standard contracts in the Oregon tariffs may contain some terms inconsistent with existing Idaho Commission precedent on certain terms, such as the

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60 http://www.pacificorp.com/es/cg/cqfp.html.
61 http://www.idahopower.com/AboutUs/RatesRegulatory/Tariffs/tariffPDF.cfm?id=269.

90/110 band. Thus, I believe a standard Idaho contract should be developed and made publicly available based upon existing Idaho orders, which already address many of the material terms of a QF PPA.

I recommend the Commission adopt these standard tariff requirements based on the Oregon tariffs, or some form of reasonable substitute with similar requirements.

Q. DO YOU HAVE ANY SUGGESTED IMPROVEMENTS IN THE EVENT THAT THE COMMISSION DOES NOT UNDERTAKE TO MAKE AVAILABLE A STANDARD CONTRACT DELINEATING ALL TERMS AND CONDITIONS?

A. Yes, even without a publicly available standard contract setting forth all terms, many terms in QF PPAs have been set by the Commission through its history of implementing PURPA. In the past, when the utilities have sought to implement a new condition in QF contracts, the utilities have filed an application seeking Commission approval prior to implementing such new conditions. For example, Case No. IPC-E-04-2, where Idaho Power sought, but did not receive, approval to start including a term in QF contracts that declared Idaho Power would have a right of first refusal to purchase any renewable energy credits generated by a QF selling at avoided cost rates. Also, in Case No. IPC-E-03-16, Idaho Power filed an application to modify insurance and lien rights authorized as satisfactory risk mitigation measures in levelized QF contracts. In Case No. IPC-E-07-04, Idaho Power applied for Commission approval of its proposal to implement daily load shape pricing in QF contracts. In each of these cases, interested parties had the opportunity to comment on the utility's proposal, and the Commission approved a term that was less onerous on QFs than that initially sought by the utility.

More recently, the utilities have simply begun inserting major new terms into QF contracts when QFs have requested PPAs, without first obtaining Commission approval in proceeding where all parties can comment. Recent contract terms implemented in this manner include the delay security liquidated damages provisions and the terms clouding the QF's title to environmental attributes, discussed above. The utilities then rely upon the Commission orders approving contracts that contain such clauses as though the clauses were fully vetted with comments by all interested parties in an open process. Vetting new contract terms in an individual contract approval case is inappropriate because few QFs are likely to comment in opposition to approval of the contract, knowing that the developer at issue must be anxious to secure Commission approval. I recommend that the Commission admonish this new utility practice of unilaterally inserting clauses into QF contracts without first seeking Commission approval that the term is fair.

Q. DO YOU HAVE ANY OTHER SUGGESTIONS FOR QF TARIFFS?

A. Yes. FERC's regulations allow QF to choose to sell to a utility on an "as available" or nonfirm basis, rather than pursuant to a legally enforceable obligation over a specified term.[62] The rates are calculated at the time of delivery, rather than at the time that the QF obligates itself to a legally enforceable obligation. In today's market, the "as available" rates will be lower than

[62] I8 C.F.R. § 292.304(d)(1).

those in a contract over a specified term because market prices are lower than the cost to procure a new resource. However, an "as available" contract option is useful to many QFs, and would provide the utility with low-cost power in certain circumstances.

For example, if a QF is unable to resolve a dispute with a utility prior to its project coming on line, an "as available" contract can provide the QF with the opportunity to complete construction and achieve commercial operation prior to resolving the dispute. This may also be a useful option for QFs who would prefer to use their generation to serve their own load during most of the time, but sell to the utility "as available" when the output is not needed or desired to meet the QF's host load.

Q. WHAT IS YOUR RECOMMENDATION?

A. Idaho Power has a tariff contract for nonfirm or "as available" deliveries in its Schedule 86, but neither Avista nor Rocky Mountain Power have such a tariff standard contract for nonfirm deliveries. A tariff contract is important for QFs seeking to exercise this element of FERC's regulations because a QF may want to exercise this option to make nonfirm deliveries on short notice, such as in my example where the QF is unable to reach agreement with the utility on the terms of a long term contract. I recommend that Avista and Rocky Mountain Power also file a nonfirm standard contract similar to Idaho Power's Schedule 86. QFs should have the opportunity to comment on the proposed standard contracts prior to Commission approval.

VII. TRANSMISSION AND INTERCONNECTION ISSUES

Q. DO YOU HAVE ANY RECOMMENDATIONS WITH REGARD TO QF TRANSMISSION AND INTERCONNECTION ISSUES?

A. I believe this is another issue where QFs are providing benefits to ratepayers in excess of what a utility's own resources will provide. Under the existing Idaho precedents, PURPA QF projects are solely responsible for the interconnection costs required to interconnect their proposed projects to the utilities' systems, and are almost always responsible for the network transmission upgrades required to deliver their energy from the point of interconnection with utility's system to load. In some cases, Idaho Power and the ratepayers have shared in the cost of network upgrades.[63] Essentially, under those few authorized sharing arrangements, the QF pays 25% of the total cost regardless of its performance, and it obtains a refund of an additional 50% paid up front only if it performs.

In contrast, all prudently incurred interconnection and transmission costs associated with a utility-owned project will be included in customer rates. Similarly, when federal jurisdiction applies to an interconnection, developers receive a refund for the entire cost of network transmission upgrades required for their projects under FERC interconnection rules.[64]

The Commission could improve its existing precedent on this issue in two ways. First, the existing cost sharing arrangement is non-binding based upon the Commission orders implementing it. The Commission should provide QFs with the assurance of an established

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[63] IPUC Order No. 32136, Case No. IPC-E-09-25 (2010).

[64] *Standardization of Small Generator Interconnection Agreements and Procedures*, FERC Order No. 2006, at ¶ 40, Docket No. RM02-12 (May 12, 2005).

policy. Second, the policy should treat QFs the same as the alternative to QFs. QFs should be treated the same as the utilities and other developers. When the Montana Public Service Commission recently examined this issue it stated NorthWestern Energy "improperly sought to assign all network upgrade costs to the QF instead of the amount of those costs that exceeded what [NorthWestern Energy] otherwise would incur to connect its avoidable resource."[65] This is a fair approach, and I recommend that the Idaho Commission establish the same policy for equal treatment by entitling the QF to 100 percent refund of network transmission upgrades on similar terms to those provided for FERC jurisdictional interconnections.

CONCLUSION

Q. DR. READING, DO YOU HAVE AN CONCLUDING COMMENTS REGARDING THIS DOCKET AND YOUR RECOMMENDATIONS?

A. Yes, I do. I am fully cognizant of the situation Idaho Power is in with respect to the magnitude of wind generation it is being required to integrate into its system. I believe, based on my many years of involvement in utility regulation in Idaho, that this was part of the genesis of this docket. I also believe Idaho Power, along with the other two investor-owned utilities, is using that fact to dismantle PURPA in Idaho without regard for the ratepayer or this Commission's obligations under PURPA. The SAR methodology has been resilient in the past

[65] *In re NorthWestern Energy's Application for Approval of Avoided Cost Tariff for New Qualifying Facilities*, Montana PSC Docket No. D2010.7.77, Order No. 7108e, p. 32, ¶ 84 (Oct. 19, 2011), available online at http://psc.mt.gov/Docs/ElectronicDocuments/.

in responding to changed circumstances, and it continues to stand out as the single best methodology for this Commission to use in fulfilling its obligations under PURPA.

I do not accept Idaho Power's "the sky is falling" basis for making wholesale destructive changes to the PURPA implementation that has taken this Commission years to develop and fine tune. The Commission currently has the tools at hand to respond to changing economic conditions while at the same time properly implementing PURPA.

Q. YOU HAVE BEEN QUESTIONED IN THE PAST AS TO THE, IF YOU WILL, INTEGRITY OF YOUR TESTIFYING ON BEHALF OF THE PURPA INDUSTRY WHILE ALSO TESTIFYING ON BEHALF OF RATEPAYERS – SPECIFICALLY THE INDUSTRIAL CUSTOMERS OF IDAHO POWER. CAN YOU ADDRESS THAT PERCEIVED CONFLICT?

A. I would be happy to do so. To find evidence that the ratepayers and the PURPA industry's interests are aligned, one need look no farther than the first page of my testimony. I am testifying today on behalf of Avista's largest retail customer who also is Avista's largest PURPA vendor. I am also testifying on behalf of one of Idaho Power's largest customers who is also one of Idaho Power's largest PURPA vendors. Finally, I am testifying on behalf of Idaho's largest and most successful PURPA wind developers. The fact that these three entities have common ground in promoting a reasonable and fair implementation of PURPA in opposition to the three investor-owned utilities is significant because all three live in the real world.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY THE "REAL WORLD"?

A. First, none of my clients operate in a state sanctioned monopoly environment and none are virtually assured a return on investment. All are rational actors in highly competitive industries. The fact that all three see a need to have a robust independent power market and at the same time have fair retail rates is not an oxymoron – it is in the best interests of both the PURPA developers and the ratepayer. The single fact that sophisticated self-interested ratepayers have joined forces with a sophisticated self-interested PURPA developer to advocate against the PURPA-killing proposals made by the utilities is compelling -- and should be very instructive to the Commission as it deliberates on the many complex and difficult issues presented in this docket.

Q. DOES THAT CONCLUDE YOUR TESTIMONY ON MAY 4, 2012?

A. Yes it does.

Don C. Reading

Present position	Vice President and Consulting Economist
Education	B.S., Economics — Utah State University M.S., Economics — University of Oregon Ph.D., Economics — Utah State University
Honors and awards	Omicron Delta Epsilon, NSF Fellowship
Professional and business history	Ben Johnson Associates, Inc.: 1989 --- Vice President 1986 ---- Consulting Economist Idaho Public Utilities Commission: 1981-86 Economist/Director of Policy and Administration Teaching: 1980-81 Associate Professor, University of Hawaii-Hilo 1970-80 Associate and Assistant Professor, Idaho State University 1968-70 Assistant Professor, Middle Tennessee State University
Experience	Dr. Reading provides expert testimony concerning economic and regulatory issues. He has testified on more than 35 occasions before utility regulatory commissions in Alaska, California, Colorado, the District of Columbia, Hawaii, Idaho, Nevada, North Dakota, Texas, Utah, Wyoming, and Washington.

Dr. Reading has more than 30 years experience in the field of economics. He has participated in the development of indices reflecting economic trends, GNP growth rates, foreign exchange markets, the money supply, stock market levels, and inflation. He has analyzed such public policy issues as the minimum wage, federal spending and taxation, and import/export balances. Dr. Reading is one of four economists providing yearly forecasts of statewide personal income to the State of Idaho for purposes of establishing state personal income tax rates.

In the field of telecommunications, Dr. Reading has provided expert testimony on the issues of marginal cost, price elasticity, and measured service. Dr. Reading prepared a state-specific study of the price elasticity of demand for local telephone service in Idaho and recently conducted research for, and directed the preparation of, a report to the Idaho legislature regarding the status of telecommunications competition in that state.

Dr. Reading's areas of expertise in the field of electric power include demand forecasting, long-range planning, price elasticity, marginal and average cost pricing, production-simulation modeling, and econometric modeling. Among his recent cases was an electric rate design analysis for the Industrial Customers of Idaho Power. Dr. Reading is currently a consultant to the Idaho Legislature's Committee on Electric Restructuring.

Since 1999 Dr. Reading has been affiliated with the Climate Impact Group (CIG) at the University of Washington. His work with the CIG has involved an analysis of the impact of Global Warming on the hydo facilities on the Snake River. It also includes an investigation into water markets in the Northwest and Florida. In addition he has analyzed the economics of snowmaking for ski area's impacted by Global Warming.

Among Dr. Reading's recent projects are a FERC hydropower relicensing study (for the Skokomish Indian Tribe) and an analysis of Northern States Power's North Dakota rate design proposals affecting large industrial customers (for J.R. Simplot Company). Dr. Reading has also performed analysis for the Idaho Governor's Office of the impact on the Northwest Power Grid of various plans to increase salmon runs in the Columbia River Basin.

Dr. Reading has prepared econometric forecasts for the Southeast Idaho Council of Governments and the Revenue Projection Committee of the Idaho State Legislature. He has also been a member of several Northwest Power Planning Council Statistical Advisory Committees and was vice chairman of the Governor's Economic Research Council in Idaho

While at Idaho State University, Dr. Reading performed demographic studies using a cohort/survival model and several economic impact studies using input/output analysis. He has also provided expert testimony in cases concerning loss of income resulting from wrongful death, injury, or employment discrimination. He is currently a adjunct professor of economics at Boise State University (Idaho economic history, urban/regional economics and labor economic.)

Dr. Reading has recently completed a public interest water rights transfer case. He is currently a member of the Boise City Public Works Commission.

Publications

"Energizing Idaho", Idaho Issues Online, Boise State University, Fall 2006. www.boisestate.edu/ history/issuesonline/fall2006_issues/index.html

The Economic Impact of the 2001 Salmon Season In Idaho, Idaho Fish and Wildlife Foundation, April 2003.

The Economic Impact of a Restored Salmon Fishery in Idaho, Idaho Fish and Wildlife Foundation, April, 1999.

The Economic Impact of Steelhead Fishing and the Return of Salmon Fishing in Idaho, Idaho Fish and Wildlife Foundation, September, 1997.

"Cost Savings from Nuclear Resources Reform: An Econometric Model" (with E. Ray Canterbery and Ben Johnson) *Southern Economic Journal*, Spring 1996.

A Visitor Analysis for a Birds of Prey Public Attraction, Peregrine Fund, Inc., November, 1988.

Investigation of a Capitalization Rate for Idaho Hydroelectric Projects, Idaho State Tax Commission, June, 1988.

"Post-PURPA Views," In Proceedings of the NARUC Biennial Regulatory Conference, 1983.

An Input-Output Analysis of the Impact from Proposed Mining in the Challis Area (with R. Davies). Public Policy Research Center, Idaho State University, February 1980.

Phosphate and Southeast: A Socio Economic Analysis (with J. Eyre, et al). Government Research Institute of Idaho State University and the Southeast Idaho Council of Governments, August 1975.

Estimating General Fund Revenues of the State of Idaho (with S. Ghazanfar and D. Holley). Center for Business and Economic Research, Boise State University, June 1975.

"A Note on the Distribution of Federal Expenditures: An Interstate Comparison, 1933-1939 and 1961-1965." In *The American Economist*, Vol. XVIII, No. 2 (Fall 1974), pp. 125-128.

"New Deal Activity and the States, 1933-1939." In *Journal of Economic History*, Vol. XXXIII, December 1973, pp. 792-810.

REQUEST FOR PRODUCTION NO. 26[sic]: Reference the Direct Testimony of Mark Stokes, p. 18, describing the differential between what Idaho Power will pay for PURPA generation in 2012 and the amount it would pay to purchase the same amount of generation as a "firm" product in the Mid-C market.

(a) Please provide a detailed definition and an example of a "firm" product, including the maximum term (years and months) for which Idaho Power could secure a firm market purchase in 2012. Does this cost include the cost of firm transmission from Mid-C to Idaho Power's system?

(b) Please estimate the amount of firm transmission (MW) Idaho Power possesses or could secure from Mid-C to Idaho Power's loads.

(b)[sic] Using the same figures for the cost of firm market product used in the testimony, please provide the differential for the cost for Langley Gulch (including all variable and fixed costs passed onto customers through rates) for each year from 2012 to 2021, in dollars and in $/MWh. Please prorate the costs of market purchases for 2012 to account for the date Idaho Power estimates Langley Gulch costs will be incurred by customers in that year.

(c) Please provide a detailed explanation of the assumptions used in the calculation in the testimony and in the calculations in response to this request.

RESPONSE TO REQUEST FOR PRODUCTION NO. 26[sic]:

(a) The following is taken from the Western Systems Power Pool ("WSPP") website (www.wspp.org) which includes information regarding energy trading in the western United States:

> The Current WSPP Agreement effective October 21, 2011, is the most commonly used standardized power sales contract

> in the electric industry. It is approved by the FERC and used by jurisdictional and non-jurisdictional entities. Once signed, the Agreement allows instant access to power trading within the membership.
>
> The mission of the organization is to provide a catalyst for an efficient and robust wholesale electric power market. WSPP accomplishes this by constantly facilitating refinements to the Agreement and promoting trading relationships.

Under the WSPP Agreement, a "firm" product is defined as a firm capacity and/or energy transaction whereby the Seller has agreed to sell or exchange and the Purchaser has agreed to buy or exchange for a specified period available capacity with or without associated energy which may include a Physically-Settled Option and a capacity transaction in accordance with the Agreement, including Service Schedule C, and any applicable Confirmation. The current maximum term at Mid-C on the ICE is through the 2015 calendar year. The cost does not include transmission from Mid-C to Idaho Power's system.

(b) Each month, the Idaho Power Delivery business unit notifies Idaho Power's Power Supply business unit of the transmission allocations set aside to serve network load for the next 14 months. Monthly amounts vary, but July has historically been the most constrained month. The most recent report from Delivery indicates a total of 134 MW of firm transmission capacity between Mid-C and Idaho Power is set aside to serve network load in July 2012.

(b)[sic] Idaho Power has not performed this analysis or compiled the data that would be required.

(c) The comparisons between the cost of PURPA generation and firm purchases from the Mid-C market are based on the fixed contract price of PURPA generation multiplied by the expected generation from each project on a monthly basis. The Mid-C market comparison was done by taking the same amount of energy and multiplying it by the same long-term forward price curve provided in the Company's response to Exergy's Production Request No. 25[sic].

The response to this Request was prepared by M. Mark Stokes, Power Supply Planning Manager, Idaho Power Company, in consultation with Donovan E. Walker, Lead Counsel, Idaho Power Company.

REQUEST FOR PRODUCTION NO. 29[sic]: Reference the Direct Testimony of Mark Stokes, p. 39, stating, "The estimated 20-year, levelized cost of Langley Gulch is $68.55 per MWh using a 90 percent capacity factor assumption (to be consistent with the SAR capacity factor assumption), and Idaho Power's current natural gas price forecast."

(a) Please provide work papers and all cost assumptions for the $68.55 per MWh figure for Langley Gulch, including interconnection and transmission costs, gas price and transportation/storage costs, heat rate, assumed heat rate degradation, equivalent availability factor, capital cost, variable O&M, fixed O&M, O&M escalation rates, and inflation, as well as any other cost assumptions. Please provide the basis for each assumption for each of the listed items.

(b) Please provide the levelized $/MWh cost of Langley Gulch for both energy and capacity at the 84% capacity the Company expects the facility will have available for planning purposes. Reference IPUC Order 30392, p. 17.

(c) Please provide the levelized $/MWh cost of Langley Gulch for both energy and capacity at the 20 year average 49% capacity factor provided in Karl Bokenkamp's Direct Testimony, p. 23.

(d) Please explain if Idaho Power will commit to pass onto its customers a 20-year levelized cost for Langley Gulch that will not exceed the estimates above (allowing for adjustment to customers' rates only to account for different capacity factors).

RESPONSE TO REQUEST FOR PRODUCTION NO. 29[sic]:

(a) For questions (a), (b), and (c), please see the appropriate confidential file provided on the confidential CD. The confidential CD will be provided to those parties that have executed the protective agreement in this matter. Calculations in each of the three confidential spreadsheets include assumptions for all of the factors listed in question (a) with the exception of heat rate degradation, which has no material impact on the levelized production cost, and equivalent availability factor which is not necessary to calculate the levelized cost of production. For question (a), please see the confidential file, *PURPA CCCT 90%.pdf*, provided on the confidential CD.

(b) Please see the confidential file, *PURPA CCCT 84%.pdf*, provided on the confidential CD. The confidential CD will be provided to those parties that have executed the protective agreement in this matter.

(c) Please see the confidential file, *PURPA CCCT 49%,* provided on the confidential CD. The confidential CD will be provided to those parties that have executed the protective agreement in this matter.

(d) No.

The response to this Request was prepared by M. Mark Stokes, Power Supply Planning Manager, Idaho Power Company, in consultation with Donovan E. Walker, Lead Counsel, Idaho Power Company.

REQUEST FOR PRODUCTION NO. 33[sic]: Reference the Direct Testimony of Karl Bokenkamp, p. 25, describing Idaho Power's proposed assumption that each thermal unit will assigned an incremental cost based on full load operation.

(a) Is it true that when a thermal unit is operated at less than full load that the incremental cost per MWh increases?

(b) For each of the Company's thermal units, please provide: (1) heat rate at maximum output, (2) heat rate at minimum operating output, (3) incremental energy cost at the heat rate in (1) and (2).

(c) For each of the Company's thermal units, please provide the number of hours per year in the years 2008 through 2011 that the unit operated at full load operation.

RESPONSE TO REQUEST FOR PRODUCTION NO. 33[sic]:

(a) It is true that when a thermal unit is operated at substantially less than full load, the incremental cost per MWh does increase. This is because the efficiency of a generating unit decreases when it is operated at substantially below its design loading. However, depending on design of the individual unit, the highest operating efficiency (the best or lowest heat rate) may occur at less than full load. This is similar to fuel efficiency for your car – your car may be capable of running at 70 miles per hour, but your best fuel efficiency may occur at 55 miles per hour.

(b) Please see the Excel file provided on the non-confidential CD.

(c) Please see the Excel file provided on the non-confidential CD. In addition to providing the requested information, another analysis has been conducted to determine the number of hours that each unit operated at or above 90 percent of full load. The number of hours of operation at or above 90 percent of full load provides a good indication of the number of hours the units were operated at high loads.

The response to this request was prepared by Karl Bokenkamp, Director Operations Strategy, Idaho Power Company, in consultation with Donovan E. Walker, Lead Counsel, Idaho Power Company.

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Response to Request for Production No. 33

33(b) For each of the Company's thermal units, please provide: (1) heat rate at maximum output, (2) heat rate at minimum operating output, (3) incremental energy cost at the heat rate in (1) and (2).

	Heat Rate at Normal Full Load (Btu/kWh)	Heat Rate at Min Op. Output (Btu/kWh)	Assumed Fuel Cost ($/MMBtu)	Assumed Variable O&M Cost ($/MWh)	Incremental Energy cost at Max Output (full load) ($/MWh)	Incremental Energy cost at Min. Op. Output ($/MWh)
Jim Bridger Unit #1	9,791	11,951	2.01	0.57	20.21	24.55
Jim Bridger Unit #2	10,661	11,921	2.01	0.57	21.96	24.49
Jim Bridger Unit #3	10,068	12,075	2.01	0.57	20.77	24.79
Jim Bridger Unit #4	10,913	11,957	2.01	0.57	22.46	24.56
Boardman	9,600	11,250	1.79	0.81	17.97	20.92
Valmy Unit #1	10,000	11,300	2.51	1.55	26.64	29.90
Valmy Unit #2	9,500	10,800	2.51	1.55	25.38	28.64
Danskin Unit #1	10,446	11,901	4.62	3.03	51.32	58.04
Danskin Unit #2	12,944	12,944	4.62	2.88	62.71	62.71
Danskin Unit #3	13,115	13,115	4.62	2.88	63.50	63.50
Bennett Mountain	10,572	12,045	4.62	3.03	51.90	58.71

Notes:

1. Heat rates are approximate and are dependent on a number of factors.
2. Heat rates are for normal full load operation and normal minimum operational loadings.
3. For Valmy, the Operating Procedures Criteria (OPC) specifies how each owner's coal consumption is assigned based on usage.
4. Fuel costs are estimates and are based on values used in previous AURORA analyses. Fuel costs have a significant impact on incremental cost.
5. Variable O&M costs are approximate and are based on values used in previous AURORA analyses
6. Output of combustion turbines varies with temperature (output decreases as temperatures increases). The above estimates are based on an ambient temperature of 59 degrees F.
7. For Danskin Unit #1 and Bennett Mountain, minimum load is 60% of the full load output.
8. Because of their lower output and efficiency, Danskin Unit #2 and #3 are not currently operated at reduced loading levels - i.e., their normal normal minimum operating output is fully loaded.
9. Salmon diesels not included in this response.

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33(c) For each of the Company's thermal units, please provide the number of number of hours per year in the years 2008 through 2011 that the unit operated at full load.

Unit	Number of hours IPCo operated its share of each unit at >= full load (net dependable capacity) 2008	2009	2010	2011
Jim Bridger Unit #1	597	729	1,934	200
Jim Bridger Unit #2	1	1,338	1,120	314
Jim Bridger Unit #3	399	1,749	988	478
Jim Bridger Unit #4	1,176	1,459	1,758	314
Boardman	493	28	1,107	899
Valmy Unit #1	834	18	882	769
Valmy Unit #2	5,733	1,668	1,003	515
Danskin Unit #1	83	36	65	40
Danskin Unit #2	11	40	-	14
Danskin Unit #3	5	38	-	11
Bennett Mountain	36	98	37	52

Unit	Number of hours IPCo operated its share of each unit at >= 90% of full load (net dependable capacity) 2008	2009	2010	2011
Jim Bridger Unit #1	6,538	6,086	4,786	3,176
Jim Bridger Unit #2	6,969	5,803	6,744	3,321
Jim Bridger Unit #3	7,298	6,628	6,382	2,615
Jim Bridger Unit #4	5,641	6,535	6,470	3,365
Boardman	6,882	5,535	7,152	4,192
Valmy Unit #1	6,411	5,447	4,176	1,251
Valmy Unit #2	6,387	6,463	3,205	948
Danskin Unit #1	721	636	560	369
Danskin Unit #2	34	48	16	20
Danskin Unit #3	20	43	16	16
Bennett Mountain	125	489	218	213

Notes:
1. This analysis considers the operation of Idaho Power's share of each unit (Salmon diesels not included).
2. Ratings for several units have changed slightly over the time period in question. For this analysis, the ratings used for full load are as follows:

Unit	Total Plant - Full Load Rating (net dependable capacity - MW) 2008	2009	2010	2011
Jim Bridger Unit #1	530	530	530	531
Jim Bridger Unit #2	530	530	527	527
Jim Bridger Unit #3	530	530	530	523
Jim Bridger Unit #4	530	530	530	530
Boardman	585	585	575	575
Valmy Unit #1	249	249	249	249
Valmy Unit #2	270	270	270	270
Danskin Unit #1	171	171	171	171
Danskin Unit #2	45	45	45	45
Danskin Unit #3	45	45	45	45
Bennett Mountain	164	164	164	164

Idaho Power share of Bridger is 1/3, Boardman is 10% and Valmy is 50%.

REQUEST FOR PRODUCTION NO. 37[sic]: Reference the Direct Testimony of Karl Bokenkamp, p. 29, "Idaho Power proposes that any QFs with signed contracts and any 'queued' QFs be included in Idaho Power's resource portfolio for purposes of calculating future avoided costs because they can impact future avoided costs. For purposes of calculating avoided costs, Idaho Power proposes that upon its receipt of a written request from a QF for contract pricing, the QF is designated as 'queued.'"

(a) For the years 2008 through 2012, please identify the QFs from whom Idaho Power has received a written request for contract pricing with IRP methodology rates (using numbers or other identifiers to preserve confidentiality if necessary).

(b) For each of the projects listed in response to (a), please provide the date of the request for pricing, and whether the QF executed a PPA with Idaho Power for the project, and whether the IPUC has approved the PP A for which pricing was requested.

RESPONSE TO REQUEST FOR PRODUCTION NO. 37[sic]:

(a) – (b) Idaho Power does not keep detailed historical records of all requests received that do not evolve into a completed purchase power agreement. However, below is a list of projects that Idaho Power has recollection of making these requests in recent years.

Individual Project Detail			
Resource Type	**Proposed MW**	**Date of Request**	**Contract status**
Cogen	97.00	Nov-11	
Hydro	2.25	Feb-12	
Solar	20.00	Sep-11	
Solar	60.00	2008, 2010 and 2012	
Solar	20.00	Mar-11	
Solar	20.00	Mar-11	

Solar	20.00	Nov-11	
Solar	20.00	Nov-11	
Solar	20.00	Nov-11	
Solar	40.00	Jun-11	
Solar	35.00	Sep-11	
Wind	80.00	Sep-11	
Wind	38.00	Sep-08	Approved Contract, Project on-line
Wind	80.00	Jan-10	Approved Contract, Project on-line
Wind	60.00	Sep-11	
Biomass	3.00	Nov-10	Approved Contract
Biomass	22.00	Jul-11	Approved Contract
Solar	20.00	Oct-10	Approved Contract
Wind	40.00	Jan-11	Approved Contract
Wind	24.00	Sep-11	
Total	721.25		

The response to this Request was prepared by Randy C. Allphin, Energy Contract Coordinator Leader, Idaho Power Company, in consultation with Donovan E. Walker, Lead Counsel, Idaho Power Company.

<u>REQUEST FOR PRODUCTION NO. 39[sic]:</u> Reference the Direct Testimony of Karl Bokenkamp, p. 22, proposing that an SCCT replace a CCCT for purposes of calculating the capacity component of the IRP Methodology calculation.

(a) For the years 2008 through 2011, please provide the number of days per year that Idaho Power operated its gas peakers (Bennett Mountain or Danskin) to meet load.

(b) Please provide the number of days per year that Idaho Power forecasts to use Langley Gulch to meet load requirements, as assumed in Idaho Power's load and resource balance from its IRP.

<u>RESPONSE TO REQUEST FOR PRODUCTION NO. 39[sic]</u>:

(a) The number of days that Idaho Power operated its gas peakers to meet load for the years 2008 through 2011 is as follows:

Year	Danskin	Bennett Mountain
2008	106	45
2009	86	62
2010	77	32
2011	85	44

(b) Idaho Power's Monthly Average Energy Load and Resource Balance (2011 IRP Appendix C, pages 22 through 41) and Idaho Power's Peak-Hour Load and Resource Balance (2011 IRP Appendix C, pages 44 through 63) do not forecast the number of days that Langley Gulch will be used to serve load. These resource balances primarily compare the amount of forecast monthly energy (or peak-hour capacity) available from each specific resource to serve the forecast monthly average load (or peak-hour load).

For the number of days that Langley Gulch operates as determined in an AURORA analysis which models the 2011 IRP preferred portfolio under 50^{th} percentile (median) water condition and load conditions with updated natural gas and load forecasts and no carbon taxes, please see the Excel file provided on the non-confidential CD.

The response to this request was prepared by Karl Bokenkamp, Director Operations Strategy, Idaho Power Company, in consultation with Donovan E. Walker, Lead Counsel, Idaho Power Company.

39(b) Please provide the number of days per year that Idaho Power forecasts to use Langley Gulch to meet its load requirements, as assumed in Idaho Power's load and resource balance from its IRP.

Year	Number of days per year that Langley Gulch operates as determined by AURORA analysis
2013	320
2014	315
2015	343
2016	359
2017	358
2018	352
2019	358
2020	357
2021	359
2022	364
2023	363
2024	361
2025	362
2026	363
2027	362
2028	366
2029	363
2030	363

Notes:

1. The AURORA analysis does not determine whether the generating unit's output is being used to serve system load or if it is being used to support market sales.

REQUEST FOR PRODUCTION NO. 41: Reference the Direct Testimony of Karl Bokenkamp, p. 29, lines 6-8. Please state whether Idaho Power intends for all "queued" QFs, as defined in the testimony, to be included in Idaho Power's IRP for all purposes, including prudency of the decision to build a new utility-owned plant in a CPCN proceeding for the DSM investments. Please explain how including all "queued" QFs in the load and resource balance for all purposes will impact future utility plant CPCN applications and DSM proposals, and other action items in the IRP.

RESPONSE TO REQUEST FOR PRODUCTION NO. 41: Historically, Idaho Power has only included signed qualifying facility ("QF") contracts in the load and resource balance used to prepare the Integrated Resource Plan ("IRP") because of the uncertainty surrounding if and when additional projects may come on-line. Idaho Power's need for new resources, both supply-side and demand-side, is driven by peak-hour load growth. As long as the vast majority of new QF projects continue to be wind resources, Idaho Power does not believe the "queued" QF projects would impact future utility plant Certificate for Public Convenience and Necessity applications, demand-side management proposals, or other IRP action items.

If Idaho Power had included a total of 700 megawatts ("MW") of QF wind in the load and resource balance used in the preparation of the 2011 IRP, the resulting preferred portfolio would likely be unchanged. Because wind resources can only be counted on to provide 5 percent of nameplate capacity towards meeting peak-hour load, 700 MW of wind only displaces 35 MW of summertime capacity needs.

The queuing process as described in Mr. Bokenkamp's testimony would be used to determine when the highest incremental cost displaceable resource has been fully offset by the proposed QF projects. Once this level is reached, the model would be re-run to include the cumulative QF project energy and determine the new highest increment cost displaceable resource for each hour. The process of determining the highest cost displaceable resource for each hour makes use of the most recent IRP data, but does not change the IRP data or results. Therefore, for the IRP planning process, Idaho Power would continue to use the forecast generation for all QF projects with signed contracts.

The response to this Request was prepared by M. Mark Stokes, Power Supply Planning Manager, Idaho Power Company, in consultation with Donovan E. Walker, Lead Counsel, Idaho Power Company.

AVISTA CORPORATION
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	IDAHO	DATE PREPARED:	4/30/2012
CASE NO:	GNR-E-11-03	WITNESS:	Clint Kalich
REQUESTER:	Clearwater	RESPONDER:	Clint Kalich
TYPE:	Production Request	DEPARTMENT:	Energy Resources
REQUEST NO.:	CW-11	TELEPHONE:	(509) 495-4532

REQUEST:

Please provide all studies, analysis, or documents used to develop this $45/kw amount.

RESPONSE:

The $45/kW delay security amount is intended to create a source of liquid funds which the utility can draw upon in the event that damages are incurred if a new project does not meet its online date. A PURPA contract for Clearwater Paper's facilities do not require delay liquidated damages, as its facility already is operating and Avista does not presently require its PURPA contracts to contain delivery term or operating security.

In 2009, Avista commissioned a survey of utilities and their required delay (also referred to "development") security amounts for renewable projects. The results are as follows:

Utility	Security Level and Structure	Security Requirements Based on One Year or Revenues, if applicable	Operating Period and/or Development Security Requirements ($/kW equivalent)
PG&E 2009 RFO	Development period security is $15/kW upon contract execution. Development security is $100/kW times the capacity factor (minimum of $50/kW) once the contract is approved by the CPUC Delivery term security is equal to 12 months of revenue for a 20 year contract.		$50/kW Development Security Minimum
Southern California Edison 2009 RFP	Development period security is equal to $30/kW for intermittent resources. Delivery term security is equal to 5% of the value of the total energy payments in the		$30/kW Development Security

	contract.		
San Diego Gas and Electric 2007 RFP	Two times estimated annual production times $15/MWh in place for the entire term of the contract	$7,884,000	$78.84/kW
Public Service of Colorado (2003)	$75/kW of design maximum output	$7,500,000	$75/kW
Public Service of Oklahoma/Southwestern Electric Power Company	$75/kW of design maximum output	$7,500,000	$75/kW
Southwestern Public Service Company and Llano Estacado Wind LP contract (12/2001)	Fixed amount of $3,965,500 for 80 MW contract	$3,965,000 [or $4,957,000 per 100 MW]	$49.57/kW
Arizona Public Service Company	$75/kW for both development period and operating period security	$7,500,000	$75/kW
Delmarva Power (second lien also required) (2007)	$80/kW	$8,000,000	$80/kW
Hawaiian Electric Company 2008 Renewable RFP	Development period security is $30/kW and Operating Period Security is $40/kW		$30/kW Development Security

Further, both Idaho Power and Avista presently include delay liquidated damage security deposits of $45/kW. Rocky Mountain Power requires a delay liquidated damage deposit equal to the greater of $45/kW, or the full value of the first 3 months of expected electricity deliveries. Avista understands that a similar delay liquidated damages provision is defined for PURPA projects selling power into Oregon. Therefore it would appear that it is common practice to 1) apply liquidated damages to PURPA contracts and 2) a $45/kW level is reasonable, as is evidenced by practice in Idaho and other jurisdictions.

AVISTA CORPORATION
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	IDAHO	DATE PREPARED:	4/30/2012
CASE NO:	GNR-E-11-03	WITNESS:	Clint Kalich
REQUESTER:	Clearwater	RESPONDER:	Clint Kalich
TYPE:	Production Request	DEPARTMENT:	Energy Resources
REQUEST NO.:	CW-13	TELEPHONE:	(509) 495-4532

REQUEST:

Has Avista approximated its likely actual damages in the event that a QF were to delay its projected online date beyond the 180 day limit specified in the testimony? Please identify all likely costs and provide all work papers and analysis performed.

RESPONSE:

No. Such calculation would depend on the market conditions at the time of the contract.

AVISTA CORPORATION
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	IDAHO	DATE PREPARED:	4/30/2012
CASE NO:	GNR-E-11-03	WITNESS:	Clint Kalich
REQUESTER:	Clearwater	RESPONDER:	Clint Kalich
TYPE:	Production Request	DEPARTMENT:	Energy Resources
REQUEST NO.:	CW-14	TELEPHONE:	(509) 495-4532

REQUEST:

Has Avista ever guaranteed the online date of any of its utility-owned generation facilities, and promised to issue a rate payer refund, or otherwise reduce rates for the amount of estimated damages set at $45/kw or otherwise? If so, please explain the circumstances. If not, please explain why QFs need to provide such ratepayer protections but the utility does not.

RESPONSE:

Please refer to the answer to PR 15(e).

AVISTA CORPORATION
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	IDAHO	DATE PREPARED:	4/30/2012
CASE NO:	GNR-E-11-03	WITNESS:	Clint Kalich
REQUESTER:	Clearwater	RESPONDER:	Clint Kalich
TYPE:	Production Request	DEPARTMENT:	Energy Resources
REQUEST NO.:	CW-15	TELEPHONE:	(509) 495-4532

REQUEST:

Reference IPUC Order No. 30611, at p. 2, approving CWIP and AFUDC for the Reardan wind farm, which Avista intended to reach commercial online status by year end 2011, and stating "Avista believe[d] it [wa]s cost effective and prudent to secure land rights and equipment now, even though actual construction will not begin until 2011."

(a) Please explain the status of the Reardan wind farm, whether it came online as projected in 2011, its approximate online date, and the reason for any delays.

(b) Please identify and provide the costs spent by Avista on the Reardan project to date. Please identify any costs included in Avista's retail rates implicitly or explicitly.

(c) Please explain how Avista was able to change its plans for Reardan's projected online date without compromising Avista's need to acquire RPS compliant generation to meet Washington RPS targets. Did Avista acquire another RPS compliant resource instead of Reardan?

(d) What were Avista's actual costs incurred in the delayed or permanently deferred online date for Reardan? Please provide all supporting work papers and an explanation.

(e) Will Avista provide rate payers a $45/kw delay damages refund if Reardan is not online within 180 days of year end 2011, as projected in the application in Case No. AVU-E-08-04? Please explain why or why not.

RESPONSE:

(a) Avista has delayed plans for construction of the Reardan wind project. The recent acquisition of the Palouse Wind Farm through a competitive RFP meets our needs through at least 2019. The Company continues to maintain the permitted Reardan wind project as an option for future development and continues to collect data at the site.
(b) Please see the attached spreadsheet entitled "Reardan_Costs_Thru_Mar_2012.xlsx." No costs are currently included in retail rates related to the Reardan Wind Farm.
(c) Avista was able to change plans through the acquisition of the Palouse Wind Project that meets our immediate needs for RPS resources.
(d) Please see response (b).
(e) No. The alignment of customer interests is different as between a PURPA fixed-priced contract as compared to a utility-owned generation resource. As PURPA resources are provided to a utility at a fixed contract price, that contract price does not vary based on the actual cost of the PURPA generation project. To help ensure that fixed price benefit is delivered, it is in customers' interest to have PURPA contract terms structured such that

developer interests are aligned with customer interests. A utility, such as Avista, does not provide a price guarantee for its utility-owned generation assets, but instead provides long-term generation ownership value to customers at cost. In other words, customers benefit from paying only actual costs over the life of a very long-term resource. In contrast, the guarantees embedded in PURPA contracts define costs utility customers will pay over the term of the agreement. A delay damages provision is a means to ensure that developer and customer interests are aligned, and that customers receive the benefits from the PURPA contract, consistent with the pricing and other terms and conditions that have been guaranteed to the developer under the PURPA contract.

REQUEST FOR PRODUCTION NO. 7: Please identify all PURPA QF projects that are owned or partially owned by Idaho Power or any company affiliated with Idaho Power. Please describe each project in detail including ownership percentages, monthly production, in service date, power purchaser and location. Please describe the impact on each such project Idaho Power's proposals in this docket will have if they are adopted by the Commission in total.

RESPONSE TO REQUEST FOR PRODUCTION NO. 7: IDACORP owns Ida-West Energy, a non-regulated subsidiary that owns and operates nine QF projects under PURPA. Specific details related to these projects are provided in the two tables below. If Idaho Power's proposals are adopted by the Idaho Public Utilities Commission, the four Ida-West projects located in Idaho will be impacted to the same extent as any other similarly situated QF projects with which Idaho Power has FESAs under PURPA.

Project Name	Nameplate (MW)	Location	Power Purchaser	Ownership	In-Service Year
South Forks	8.20	Idaho	Idaho Power	50%	1985
Hazelton B	7.70	Idaho	Idaho Power	50%	1993
Wilson Lake	8.40	Idaho	Idaho Power	50%	1993
Falls River	9.10	Idaho	Idaho Power	50%	1993
Cove	5.00	California	Pacific Gas & Electric	50%	1990
Burney Creek	3.50	California	Pacific Gas & Electric	50%	1990
Ponderosa/Bailey	1.10	California	Pacific Gas & Electric	50%	1990
Lost Creek 1	1.10	California	Pacific Gas & Electric	50%	1989
Lost Creek 2	0.45	California	Pacific Gas & Electric	50%	1989

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Estimated Monthly Production (MWh)

Project Name	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
South Forks	0	0	0	1,498	4,160	4,815	5,484	5,173	3,942	2,272	0	0
Hazelton B	0	0	87	1,418	3,390	4,087	4,689	4,319	3,211	1,373	51	0
Wilson Lake	0	0	51	1,532	3,926	4,664	5,298	4,826	3,656	1,639	57	0
Falls River	2,627	1,957	2,652	4,922	6,350	6,255	4,702	4,314	3,803	3,713	3,538	2,842
Cove	2,055	2,448	3,609	3,228	2,590	1,140	194	6	2	16	235	1,353
Burney Creek	654	816	1,271	1,429	1,304	509	28	0	0	4	45	266
Ponderosa/Bailey	156	196	279	292	506	538	324	66	3	0	16	92
Lost Creek 1	559	509	587	562	550	492	498	502	493	528	513	528
Lost Creek 2	249	226	258	247	247	234	226	237	229	241	230	238

The response to this Request was prepared by Mark Stokes, Power Supply Planning Manager, Idaho Power Company, in consultation with Donovan E. Walker, Lead Counsel, Idaho Power Company.

DATED at Boise, Idaho, this 17th day of February 2012.

DONAVON E. WALKER
Attorney for Idaho Power Company

REQUEST FOR PRODUCTION NO. 12: Reference the Direct Testimony of Tessia Park, p 18, discussing the Company's proposed Tariff Schedule 74 (Exhibit No. 5).

(a) Please identify the provision of Idaho Power's proposed Tariff Schedule 74 that would compensate QFs for curtailments occurring without providing the required notice, or where the basis for the curtailment was not supported by the circumstances described in 18 C.F.R. § 292.304(f). If no such provision is included, please explain why.

(b) Please explain Idaho Power's basis for only proposing to provide QFs one-hour notice prior to such curtailments. Is Idaho Power aware of any FERC or state commission order that has authorized advance notice of one hour or less to QFs in implementing 18 C.F.R. § 292.304(f)?

(c) Does Idaho Power believe that it has the right to curtail QFs to under 18 C.F.R. 292.304(f) even when the applicable QF contract provides for no such curtailment? If so, please explain the basis for this position.

RESPONSE TO REQUEST FOR PRODUCTION NO. 12:

(a) Tariff Schedule 74 does not contemplate curtailing QFs without providing the required notice. Since it is not Idaho Power's intent to curtail QFs pursuant to Schedule 74 without prior notice, no such provision was included.

(b) Because wind is intermittent and because QFs do not provide Idaho Power with schedules for their generation, Idaho Power has no way of knowing how much wind generation it is going to have on its system until usually the hour or even minutes before a scheduled period. While Idaho Power is not aware of any Federal

Energy Regulatory Commission ("FERC") or state commission order that has authorized advance notice of one hour or less to QFs in implementing 18 C.F.R. § 292.304(f), there is nothing in the FERC rules which prohibits providing only one-hour notice.

(c) Yes, Idaho Power believes it has the right to curtail QFs under 18 C.F.R. § 292.304(f) even if the applicable QF contract provides for no such curtailment. It is Idaho Power's position that all FERC rules related to PURPA, including 18 C.F.R. § 292.304(f), apply to QF projects regardless of whether or not those rules are specifically mentioned in the firm energy sales agreements Idaho Power has with PURPA developers.

The response to this Request was prepared by Tessia Park, Load Serving Operations Director, Idaho Power Company, in consultation with Jason B. Williams, Corporate Counsel, Idaho Power Company.

<u>REQUEST FOR PRODUCTION NO. 13</u>: Reference the Direct Testimony of Tessia Park, p. 11, stating, "Based upon the current price of natural gas, dispatch costs of Langley Gulch will be approximately $22."

(a) What is the current price of gas used to calculate the $22 Langley Gulch dispatch cost?

(b) What is the price of gas Idaho Power expects to pay when Langley Gulch comes on line the summer of 2012, and the expected dispatch cost at that gas price?

(c) What price of gas does Idaho Power expect to pay for Langley Gulch, and what is the associated expected dispatch cost annually over the next 20 years?

(d) What is the fixed cost of Langley Gulch in $/MWh? What is the fixed cost of a QF to the Company?

<u>RESPONSE TO REQUEST FOR PRODUCTION NO. 13</u>:

(a) A natural gas price of approximately $3/MMBtu results in an estimated Langley Gulch dispatch cost of $22/megawatt-hour ("MWh").

(b) Current forward gas prices for July 2012 indicate a cost of $2.40/MMBtu. This would result in a Langley Gulch dispatch cost of $17.62/MWh.

(c) The 2011 IRP low-case, natural gas price forecast is currently viewed as the best long-term forecast Idaho Power has available, although this forecast reflects near-term gas prices that are higher than near-term forward market prices. This forecast is relatively close to the most recent natural gas price forecast issued by the Northwest Power and Conservation Council. The 2011 IRP low-case gas price forecast and the resulting dispatch cost of Langley Gulch are provided through 2030, the end of the 20-year planning horizon in the 2011 IRP, in the table below.

Year	Gas Price ($/MMBtu)	Langley Gulch Dispatch Cost ($/MWh)
2012	$4.60	$32.59
2013	$5.09	$35.89
2014	$5.43	$38.20
2015	$5.72	$40.22
2016	$6.03	$42.31
2017	$6.32	$44.27
2018	$6.59	$46.10
2019	$6.84	$47.83
2020	$7.14	$49.82
2021	$7.43	$51.85
2022	$7.57	$52.78
2023	$7.81	$54.42
2024	$8.10	$56.41
2025	$8.43	$58.65
2026	$8.76	$60.89
2027	$9.10	$63.17
2028	$9.47	$65.69
2029	$9.85	$68.30
2030	$10.24	$70.96

(d) The annual fixed costs of Langley Gulch over a 30-year life are presented in the Excel file, *Langley Gulch Fixed Costs*, provided on the non-confidential CD.

Although the second part of the question does not specify or define what should be considered a "fixed" cost for a QF contract, Idaho Power is assuming the fixed cost of a QF contract would be the fixed rate contained in the contract. As presented on page 8 of Company witness Stokes's testimony, the remaining future fixed cost of the 119 signed and approved contracts will be $3.6 billion throughout the term of the agreements. Based on estimated generation of 44,414 GWh from these projects throughout the term of the agreements, the average rate paid for this energy would be $81.06/MWh.

The response to this Request was prepared by M. Mark Stokes, Power Supply Planning Manager, Idaho Power Company, in consultation with Donovan E. Walker, Lead Counsel, Idaho Power Company.

<u>REQUEST FOR PRODUCTION NO. 17</u>: Reference the Direct Testimony of Tessia Park, p. 7, stating, the "limiting conditions on the amount of variable generation from PURPA resources which Idaho Power can accommodate are not apparent during periods of relatively high customer demand."

(a) Please define "relatively high customer demand" as used in this statement.

(b) Please estimate the level of demand at which Idaho Power believes there will be no limiting conditions for existing and contracted QFs.

(c) For the years 2010 and 2011, please provide the hours and days of the year that Idaho Power's load fell below the level described in item (b).

<u>RESPONSE TO REQUEST FOR PRODUCTION NO. 17</u>:

(a) Relatively high customer demand is not defined by a specific numerical value but rather when conditions exist such that load demands exceed the minimum hydro and thermal generation on the system.

(b) Idaho Power is unable to forecast the level of demand at which time there will be no limiting conditions for existing and contracted QFs as the level of demand is dependent on factors which the Company does not control, output of various QFs, delta between minimum and maximum load on a given day, and the hydro conditions.

(c) The Company has not prepared the analysis requested.

The response to this Request was prepared by Tessia Park, Load Serving Operations Director, Idaho Power Company, in consultation with Jason B. Williams, Corporate Counsel, Idaho Power Company.

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REQUEST FOR PRODUCTION NO. 19: Reference the Direct Testimony of Tessia Park, p. 20, stating, "Pursuant to FERC licenses Idaho Power has for its run-of-river hydro electric projects, the Company is obligated to take whatever generation flows through them; it does not have the ability to decrease or increase the generation."

(a) Please identify each of the run-of-river hydro plants and provide the capacity of each.

(b) Please provide the FERC license for each project (in electronic format if available).

(c) Please identify the provision (page number, section number, as applicable) in each FERC license that Idaho Power relies on to determine it does not have the ability to decrease or increase the generation.

(d) For each plant, please explain whether the plant has the operational capability to spill water without generating electricity, and any restrictions on Idaho Power's ability to do so.

RESPONSE REQUEST FOR PRODUCTION NO. 19:

(a) Following are the run-of-river hydro plants and their capacity:

Milner – 59.45 MW
Twin Falls – 52.74 MW
Shoshone Falls – 12.5 MW
Upper Salmon Falls A – 18 MW
Upper Salmon Falls B – 16.5 MW
Lower Salmon Falls – 60 MW
Upper Malad – 8.27 MW
Lower Malad – 13.5 MW
Bliss – 75 MW
Swan Falls – 25 MW

(b) Electronic versions of the licenses identified above are provided in the non-confidential CD.

(c) Milner. A complete reading of the Milner license shows that the Milner project is designed to generate with flows that are not used for irrigation as they pass through the project (run-of-river).

Twin Falls. A complete reading of the Twin Falls license shows that the Twin Falls project is designed to generate with flows as they pass through the project (run-of-river).

Shoshone Falls. A complete reading of the Shoshone Falls license shows that the Shoshone Falls project is designed to generate with flows as they pass through the project (run-of-river). See Article 401.

Upper Salmon Falls A. A complete reading of the Upper Salmon Falls license shows that the Upper Salmon Falls project is designed to generate with flows as they pass through the project (run-of-river). See Article 401.

Upper Salmon Falls B. A complete reading of the Upper Salmon Falls license shows that the Upper Salmon Falls project is designed to generate with flows as they pass through the project (run of river). See Article 401.

Lower Salmon Falls. A complete reading of the Lower Salmon Falls license shows that the Lower Salmon Falls project is designed to generate with flows as they pass through the project (run-of-river). See Article 401.

Upper Malad. A complete reading of the Malad license shows that the Malad project is designed to generate with flows as they pass through the project (run-of-river). See Article 401.

Lower Malad. A complete reading of the Malad license shows that the Malad project is designed to generate with flows as they pass through the project (run of river). See Article 401.

Bliss. A complete reading of the Bliss license shows that the Bliss project is designed to generate with flows as they pass through the project (run-of-river). See Article 401.

Swan Falls. A complete reading of the Swan Falls license shows that the Swan Falls project is designed to generate with flows as they pass through the project (run-of-river).

In addition, the non-confidential CD contains a copy of a Settlement Agreement between Idaho Power and the U.S. Fish and Wildlife Service which contains certain environmental provisions that place constraints around how the Company operates the Mid-Snake hydro projects (e.g.), Shoshone Falls, Bliss, Upper Salmon, and Lower Salmon).

At run-of-river projects, generation increases as flow increases and generation decreases as flow decreases.

(d) Each licensed facility has the physical capability to spill water without generating electricity. The proposed operations in the applications for FERC licenses and state water quality certifications did not include spill except when flows exceeded plant capacity or when generators tripped off-line in emergency situations. To the contrary, operations may require an amendment to the FERC licenses and/or state water quality certifications.

The response to this Request was prepared by Lewis Wardle, Senior Biologist, Idaho Power Company, in consultation with Donovan E. Walker, Lead Counsel, Idaho Power Company.

REQUEST FOR PRODUCTION NO. 20: Reference the Direct Testimony of Tessia Park, p. 23, stating, "the Company must maintain constant flows below Hells Canyon dam for environmental compliance, thus limiting the ability to curtail generation out of the Hells Canyon Complex to no less than approximately 350 MW."

(a) Please identify the individual plants/dams at the Hells Canyon Complex and the MW capacity of each.

(b) Please explain the environmental compliance requirement for each that limits the ability to curtail generation and provide the minimum generation of each individual project. Please identify the government agency imposing the compliance requirement.

(c) For each plant, please explain whether the plant has the operational capability to spill water without generating electricity. Please explain why generation cannot be curtailed to 0 MW by spilling, or to any cumulative output below 350 MW for the Complex.

RESPONSE TO REQUEST FOR PRODUCTION NO. 20:

(a) The Hells Canyon Complex consists of three projects: Brownlee, Oxbow, and Hells Canyon. The nameplate MW ratings for the aforementioned projects are as follows: Brownlee-585.40, Oxbow-190.00, and Hells Canyon-391.50

(b) FERC:

Brownlee, Oxbow, Hells Canyon

- Minimum reservoir level

Hells Canyon Dam

- Minimum flow 13,000 cubic feet per second ("cfs") at Lime Point 95 percent of the time (flows less than 13,000 cfs must be negotiated with Corps of Engineers)
- Maximum ramp rate 1 ft. / hour
- Minimum instantaneous flow 5,000 cfs

Corps of Engineer ("COE"):

Hells Canyon Dam – Requested 13,000 cfs variance

- Minimum instantaneous flow 8,500 cfs (measured at Snake River at Hells Canyon) when previous 3-day moving average Brownlee Reservoir inflow is at or above 8,500 cfs.
- Minimum instantaneous flow 11,500 cfs (measured at Snake River below McDuff Rapids) unless it would require drafting Brownlee Reservoir.
- When the previous 3-day moving average for Brownlee Reservoir inflow is less than 8,500 cfs, the instantaneous minimum Hells Canyon flow shall not fall below the previous 3-day moving average for Brownlee Reservoir inflow.

National Ocean Atmospheric Administration ("NOAA") – National Marine Fishery Services: (Endangered Species ACT)

- Provide stable Hells Canyon outflow for salmon spawning and establish minimum flow level for spring emergence.
- Provide minimum flow level for spring emergence.
- Perform entrapment surveys for spring emergence salmon to mitigate 4" ramp rate.

Environmental Protection Agency ("EPA") – State Department of Environmental Quality:

- Maintain total dissolved gases ("TDG") below Hells Canyon Dam below 110 Parts Per Million ("PPM")

United States Fish and Wildlife Service:

- Maintain TDG below 110 PPM to protect Endangered Species Bull Trout.

(c) Power plants in the Hells Canyon project are not able to decrease generation to 0 and spill water without generating electricity for the following reasons, as per regulatory standard requirements:

North American Electric Reliability Corporation ("NERC") – Western Electric Coordinating Council ("WECC"):

- NERC Standard BAL-002-1 Disturbance Control Standard ("DCS") – utilize contingency reserve to balance resources and demand and return interconnection frequency within defined limits following a reportable disturbance.

- WECC Standard BAL-002-WECC-1 Contingency Reserve – provide reliable operation of the interconnected power system. Adequate generating capacity must be available at all times to maintain scheduled frequency, and avoid loss of firm load following transmission or generation contingencies.

- NERC Standard BAL-005-0.2b Automatic Generation Control ("AGC") – provide necessary AGC to calculate Area Control Error ("ACE") and to routinely deploy the Regulating Reserve.

- WECC Standard BAL-STD-002-0 Operating Reserve – provide adequate generating capacity to be available at all times to maintain scheduled frequency and avoid loss of firm load following transmission or generation contingencies. This generating capacity is necessary to supply requirements for load variations, replace generating capacity and energy lost due to forced outages of generation or transmission equipment, meet on-demand obligations, and replace energy lost due to curtailment of interruptible imports.

FERC:

- Maintain generation MW levels for undesignated sales.

Hells Canyon Dam TDG will elevate over 110 PPM for spill above 3000 cfs.

The response to this Request was prepared by Tessia Park, Director Load Serving Operations, Idaho Power Company, in consultation with Donovan E. Walker, Lead Counsel, Idaho Power Company.

REQUEST FOR PRODUCTION NO. 21: Reference the Direct Testimony of Tessia Park, p. 1, stating dispatch costs for the Company's coal units are approximately $30/MWh and for Langley Gulch are $22/MWh.

(a) Please explain why the Company would not take its coal plants offline and instead run Langley Gulch during times when it expects to have light loading periods.

(b) For Langley Gulch, the run-of-river hydro projects, and the Hells Canyon Complex, please provide the minimum and maximum output for each that Idaho Power could reasonably expect to obtain during periods of the year that Idaho Power expects to experience light loading events. Please explain the basis for the estimates for each category.

RESPONSE TO REQUEST FOR PRODUCTION NO. 21:

(a) Coal plants cannot be shutdown and restarted on a daily basis and, consequently, they can only be turned down to minimum generating levels during light load periods in order to have their capacity available for the next days' heavy load period.

(b) When on-line, Langley Gulch will typically be operated during light loading events between its minimum and maximum generating levels. It is expected that Langley Gulch will be dispatched somewhere between its minimum and maximum levels depending primarily on system load, actual wind generation, and plant economics. The minimum and maximum levels vary seasonally, but are reasonably expected to be about 160 MW and 300 MW, respectively.

The minimum and maximum output for the run-of-river hydro projects during light loading events is dependent on water conditions in the Snake River Basin as no significant reservoir storage is available at any of Idaho Power's projects. The water conditions are very predictable with respect to short-term planning; however, a longer-term basis review of Snake River Basin streamflow records indicates pronounced season-to-season and year-to-year variability. Therefore, expected minimum and maximum output levels depend on the type of water year. For capacity planning purposes, under median water, Idaho Power expects to get 285 MW from the run-of-river plants (see 2011 IRP, page 117).

For light loading events occurring during the nearly eight month period from mid-October through May, the minimum output for the Hells Canyon Complex is driven by Idaho Power's efforts to maintain flow levels suitable for Snake River fall Chinook salmon spawning, rearing, and emergence. Idaho Power manages its operations to provide stable flows during the approximately two month spawning period (mid-October to mid-December) and, after spawning, maintains the Hells Canyon Complex outflows at or above the stable spawning flow level through rearing and emergence (mid-December through May). The spawning flow level varies from year-to-year depending on water supply in the Snake River Basin, but, in the past, has ranged from about 8,500 cfs to 14,000 cfs. While minimum output can vary from hour-to-hour depending on water management for the three dam complex, it is reasonable to estimate minimum output of about 300 MW during years when spawning flows of 8,500 cfs are provided, and about 550 MW during years when spawning flows of 14,000 cfs are provided.

Outside of the mid-October through May period, Idaho Power maintains minimum Hells Canyon Complex outflows in compliance with downstream navigation requirements. These requirements depend on several factors, including inflow to

Brownlee Reservoir and Salmon River discharge, but generally Idaho Power maintains Hells Canyon Complex outflows of 6,500 cfs or higher during this period (June to mid-October). High Brownlee inflow conditions, particularly during the early summer, may necessitate Hells Canyon Complex outflows substantially greater than 6,500 cfs. Minimum output during these high flow periods is variable, and typically quite high. During periods when Hells Canyon Complex outflows can be reduced to levels of approximately 6,500 cfs, it is reasonable to estimate minimum output levels of about 250 MW.

With respect to maximum output, Idaho Power manages the Hells Canyon Complex such that maximum output during light loading periods is typically only nominally higher than the minimum output obtained. Capacity during these periods is not needed, and the flexible generators of the Hells Canyon Complex can vary their output accordingly.

The response to this Request was prepared by M. Mark Stokes, Power Supply Planning Manager, Idaho Power Company, in consultation with Donovan E. Walker, Lead Counsel, Idaho Power Company.

REQUEST FOR PRODUCTION NO. 22: Reference the Direct Testimony of Tessia Park, p. 24, describing conditions where the Company has sufficient base load generation to service 1,100 MW of load.

(a) For the years 2010 and 2011, please provide the hours and days of the year that Idaho Power's load was at or below 1,100 MW.

(b) Please provide the number of hours, days, weeks, or months in advance that Idaho Power can accurately predict that reaching loads this low will occur.

(c) For each such occurrence, please provide the maximum load within the 7 days following the light loading event.

RESPONSE TO REQUEST FOR PRODUCTION NO. 22:

(a) There were 89 hours in the years 2010 and 2011 where the Idaho Power system load was 1100 MW or less (data from PI Series AGC_TOTALL). Idaho Power experienced load of 1100 MW or less in the months of April, May, June, October, and November of 2010 and in the months of April, May, and October of 2011. Table 22.1 provided on the non-confidential CD lists the hours when the system load was 1100 MW or less during the years 2010 and 2011.

(b) Because the term "accurately predict" is subject to a number of interpretations and is not clearly defined in this Request, Idaho Power is unable to provide the requested information.

(c) Table 22.2 provided on the non-confidential CD lists the Idaho Power system load for every hour in the months of 2010 and 2011 where there was at least one hour during the month when the system load was 1100 MW or less (data from PI

Series AGC_TOTALL). June 2011 data is included to meet the requirements specified in question 22(c) of this Request.

The response to this Request was prepared by Thomas A Noll, Ph.D., Senior Planning Analyst, Idaho Power Company, in consultation with Donovan E. Walker, Lead Counsel, Idaho Power Company.

Table 22.1

Year	Month	Day	Date	LoadHour	HourStart (Mountain)	SysLoad
2010	4	18	4/18/2010	3	4/18/2010 2:00:00 AM	1094
2010	4	18	4/18/2010	4	4/18/2010 3:00:00 AM	1087
2010	4	18	4/18/2010	5	4/18/2010 4:00:00 AM	1095
2010	4	19	4/19/2010	2	4/19/2010 1:00:00 AM	1086
2010	4	19	4/19/2010	3	4/19/2010 2:00:00 AM	1072
2010	4	19	4/19/2010	4	4/19/2010 3:00:00 AM	1085
2010	5	31	5/31/2010	2	5/31/2010 1:00:00 AM	1073
2010	5	31	5/31/2010	3	5/31/2010 2:00:00 AM	1040
2010	5	31	5/31/2010	4	5/31/2010 3:00:00 AM	1033
2010	5	31	5/31/2010	5	5/31/2010 4:00:00 AM	1035
2010	5	31	5/31/2010	6	5/31/2010 5:00:00 AM	1063
2010	5	31	5/31/2010	7	5/31/2010 6:00:00 AM	1094
2010	6	6	6/6/2010	5	6/6/2010 4:00:00 AM	1097
2010	6	7	6/7/2010	3	6/7/2010 2:00:00 AM	1084
2010	6	7	6/7/2010	4	6/7/2010 3:00:00 AM	1074
2010	6	7	6/7/2010	5	6/7/2010 4:00:00 AM	1091
2010	10	9	10/9/2010	3	10/9/2010 2:00:00 AM	1082
2010	10	9	10/9/2010	4	10/9/2010 3:00:00 AM	1072
2010	10	9	10/9/2010	5	10/9/2010 4:00:00 AM	1074
2010	10	10	10/10/2010	3	10/10/2010 2:00:00 AM	1095
2010	10	10	10/10/2010	4	10/10/2010 3:00:00 AM	1086
2010	10	10	10/10/2010	5	10/10/2010 4:00:00 AM	1092
2010	10	11	10/11/2010	3	10/11/2010 2:00:00 AM	1085
2010	10	11	10/11/2010	4	10/11/2010 3:00:00 AM	1084
2010	10	11	10/11/2010	5	10/11/2010 4:00:00 AM	1099
2010	10	17	10/17/2010	3	10/17/2010 2:00:00 AM	1100
2010	10	17	10/17/2010	5	10/17/2010 4:00:00 AM	1095
2010	10	24	10/24/2010	4	10/24/2010 3:00:00 AM	1097
2010	11	7	11/7/2010	2	11/7/2010 1:00:00 AM	1071
2010	11	7	11/7/2010	3	11/7/2010 2:00:00 AM	1067
2010	11	7	11/7/2010	4	11/7/2010 3:00:00 AM	1072
2010	11	7	11/7/2010	5	11/7/2010 4:00:00 AM	1087
2011	4	1	4/1/2011	3	4/1/2011 2:00:00 AM	1089
2011	4	1	4/1/2011	4	4/1/2011 3:00:00 AM	1089
2011	4	2	4/2/2011	2	4/2/2011 1:00:00 AM	1072
2011	4	2	4/2/2011	3	4/2/2011 2:00:00 AM	1060

Year	Month	Day	Date	LoadHour	HourStart (Mountain)	SysLoad
2011	4	2	4/2/2011	4	4/2/2011 3:00:00 AM	1051
2011	4	2	4/2/2011	5	4/2/2011 4:00:00 AM	1054
2011	4	2	4/2/2011	6	4/2/2011 5:00:00 AM	1085
2011	4	17	4/17/2011	2	4/17/2011 1:00:00 AM	1088
2011	4	17	4/17/2011	3	4/17/2011 2:00:00 AM	1081
2011	4	17	4/17/2011	4	4/17/2011 3:00:00 AM	1082
2011	4	17	4/17/2011	5	4/17/2011 4:00:00 AM	1084
2011	4	18	4/18/2011	2	4/18/2011 1:00:00 AM	1084
2011	4	18	4/18/2011	3	4/18/2011 2:00:00 AM	1077
2011	4	18	4/18/2011	4	4/18/2011 3:00:00 AM	1082
2011	4	24	4/24/2011	1	4/25/2011	1094
2011	4	25	4/25/2011	2	4/25/2011 1:00:00 AM	1065
2011	4	25	4/25/2011	3	4/25/2011 2:00:00 AM	1064
2011	4	25	4/25/2011	4	4/25/2011 3:00:00 AM	1074
2011	5	31	5/31/2011	3	5/31/2011 2:00:00 AM	1091
2011	5	31	5/31/2011	4	5/31/2011 3:00:00 AM	1093
2011	10	10	10/10/2011	2	10/10/2011 1:00:00 AM	1088
2011	10	10	10/10/2011	3	10/10/2011 2:00:00 AM	1085
2011	10	10	10/10/2011	4	10/10/2011 3:00:00 AM	1095
2011	10	14	10/14/2011	2	10/14/2011 1:00:00 AM	1097
2011	10	14	10/14/2011	3	10/14/2011 2:00:00 AM	1086
2011	10	14	10/14/2011	4	10/14/2011 3:00:00 AM	1086
2011	10	15	10/15/2011	2	10/15/2011 1:00:00 AM	1070
2011	10	15	10/15/2011	3	10/15/2011 2:00:00 AM	1051
2011	10	15	10/15/2011	4	10/15/2011 3:00:00 AM	1040
2011	10	15	10/15/2011	5	10/15/2011 4:00:00 AM	1054
2011	10	15	10/15/2011	6	10/15/2011 5:00:00 AM	1086
2011	10	16	10/16/2011	2	10/16/2011 1:00:00 AM	1070
2011	10	16	10/16/2011	3	10/16/2011 2:00:00 AM	1050
2011	10	16	10/16/2011	4	10/16/2011 3:00:00 AM	1043
2011	10	16	10/16/2011	5	10/16/2011 4:00:00 AM	1048
2011	10	16	10/16/2011	6	10/16/2011 5:00:00 AM	1069
2011	10	16	10/16/2011	1	10/17/2011	1067
2011	10	17	10/17/2011	2	10/17/2011 1:00:00 AM	1059
2011	10	17	10/17/2011	3	10/17/2011 2:00:00 AM	1052
2011	10	17	10/17/2011	4	10/17/2011 3:00:00 AM	1049
2011	10	17	10/17/2011	5	10/17/2011 4:00:00 AM	1082
2011	10	19	10/19/2011	3	10/19/2011 2:00:00 AM	1096

Year	Month	Day	Date	LoadHour	HourStart (Mountain)	SysLoad
2011	10	19	10/19/2011	4	10/19/2011 3:00:00 AM	1100
2011	10	21	10/21/2011	3	10/21/2011 2:00:00 AM	1095
2011	10	21	10/21/2011	4	10/21/2011 3:00:00 AM	1091
2011	10	22	10/22/2011	3	10/22/2011 2:00:00 AM	1090
2011	10	22	10/22/2011	4	10/22/2011 3:00:00 AM	1086
2011	10	22	10/22/2011	5	10/22/2011 4:00:00 AM	1099
2011	10	23	10/23/2011	2	10/23/2011 1:00:00 AM	1100
2011	10	23	10/23/2011	3	10/23/2011 2:00:00 AM	1087
2011	10	23	10/23/2011	4	10/23/2011 3:00:00 AM	1082
2011	10	23	10/23/2011	5	10/23/2011 4:00:00 AM	1090
2011	10	23	10/23/2011	1	10/24/2011	1099
2011	10	24	10/24/2011	2	10/24/2011 1:00:00 AM	1071
2011	10	24	10/24/2011	3	10/24/2011 2:00:00 AM	1058
2011	10	24	10/24/2011	4	10/24/2011 3:00:00 AM	1059
2011	10	24	10/24/2011	5	10/24/2011 4:00:00 AM	1087

Table 22.2 (2010 Data)

Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
4/1/2010	1285	1260	1261	1278	1324	1419	1597	1738	1737	1721	1694	1662	1630	1598	1566	1541	1541	1531	1527	1521	1607	1617	1527	1417
4/2/2010	1352	1331	1328	1344	1383	1462	1625	1745	1744	1722	1694	1657	1621	1597	1597	1621	1659	1688	1651	1672	1691	1634	1531	1424
4/3/2010	1339	1296	1276	1281	1304	1355	1442	1534	1595	1604	1589	1544	1502	1456	1413	1381	1361	1368	1385	1426	1501	1497	1428	1343
4/4/2010	1284	1251	1247	1253	1277	1325	1404	1498	1551	1555	1508	1457	1420	1375	1327	1291	1285	1300	1333	1381	1460	1449	1348	1228
4/5/2010	1163	1143	1139	1154	1190	1289	1501	1670	1670	1654	1645	1627	1588	1562	1531	1516	1507	1520	1538	1538	1601	1583	1463	1339
4/6/2010	1276	1252	1249	1263	1302	1405	1612	1755	1711	1657	1617	1581	1541	1512	1484	1459	1448	1453	1453	1465	1555	1565	1448	1311
4/7/2010	1220	1241	1242	1261	1308	1414	1630	1762	1707	1633	1554	1512	1486	1449	1399	1391	1373	1369	1371	1384	1481	1513	1399	1268
4/8/2010	1202	1180	1179	1193	1227	1326	1531	1661	1646	1613	1590	1584	1536	1504	1482	1473	1471	1479	1483	1502	1596	1612	1502	1382
4/9/2010	1316	1298	1301	1320	1363	1467	1675	1808	1779	1716	1662	1603	1550	1504	1469	1433	1401	1388	1377	1381	1480	1524	1457	1369
4/10/2010	1310	1293	1297	1310	1335	1394	1491	1581	1617	1610	1583	1532	1478	1431	1385	1361	1351	1344	1348	1354	1417	1422	1343	1256
4/11/2010	1193	1157	1145	1145	1158	1196	1266	1355	1430	1466	1457	1422	1394	1361	1348	1343	1349	1375	1381	1398	1457	1443	1334	1210
4/12/2010	1138	1113	1105	1112	1153	1249	1450	1594	1606	1607	1611	1607	1576	1558	1533	1512	1504	1496	1490	1501	1553	1556	1434	1308
4/13/2010	1245	1227	1231	1244	1286	1389	1593	1719	1692	1648	1612	1579	1549	1526	1504	1483	1468	1461	1457	1455	1515	1548	1432	1303
4/14/2010	1235	1214	1214	1230	1270	1373	1585	1700	1646	1587	1546	1521	1486	1470	1451	1433	1424	1421	1418	1412	1473	1515	1404	1278
4/15/2010	1205	1180	1179	1188	1220	1315	1524	1644	1617	1580	1549	1525	1491	1473	1465	1454	1446	1440	1430	1422	1493	1518	1401	1264
4/16/2010	1185	1153	1142	1145	1172	1256	1438	1558	1573	1557	1540	1522	1495	1491	1484	1477	1471	1465	1451	1462	1491	1479	1388	1280
4/17/2010	1197	1146	1120	1111	1121	1158	1236	1305	1381	1423	1421	1406	1380	1363	1346	1339	1346	1366	1366	1357	1403	1432	1346	1236
4/18/2010	1155	1110	1094	1087	1095	1125	1184	1250	1320	1353	1355	1346	1343	1332	1325	1324	1344	1375	1391	1395	1438	1474	1359	1214
4/19/2010	1128	1086	1072	1085	1115	1203	1398	1524	1540	1545	1546	1547	1550	1555	1561	1569	1577	1586	1590	1579	1613	1625	1484	1324
4/20/2010	1228	1187	1163	1156	1171	1248	1418	1530	1552	1566	1584	1595	1597	1609	1616	1614	1599	1593	1601	1588	1598	1563	1417	1284
4/21/2010	1208	1174	1155	1143	1161	1233	1407	1544	1576	1594	1558	1568	1551	1553	1542	1521	1517	1524	1517	1502	1537	1545	1429	1300
4/22/2010	1224	1180	1162	1164	1189	1271	1454	1582	1607	1617	1613	1611	1590	1574	1542	1525	1532	1537	1529	1516	1537	1556	1438	1305
4/23/2010	1230	1199	1185	1193	1218	1303	1496	1609	1598	1576	1555	1524	1484	1462	1430	1414	1396	1382	1362	1344	1379	1443	1379	1278
4/24/2010	1209	1170	1156	1157	1173	1215	1293	1357	1405	1416	1408	1396	1369	1344	1329	1321	1321	1333	1335	1330	1368	1418	1353	1259
4/25/2010	1194	1167	1156	1160	1173	1217	1284	1349	1414	1440	1436	1412	1395	1369	1340	1327	1329	1347	1357	1370	1428	1469	1370	1249
4/26/2010	1181	1159	1157	1173	1210	1311	1507	1615	1617	1598	1575	1564	1541	1533	1515	1505	1501	1502	1499	1491	1534	1558	1429	1288
4/27/2010	1201	1155	1139	1137	1158	1236	1404	1530	1557	1572	1580	1574	1566	1560	1537	1530	1529	1550	1544	1534	1570	1547	1433	1297
4/28/2010	1239	1214	1203	1205	1236	1334	1532	1653	1663	1645	1656	1627	1593	1570	1550	1540	1537	1544	1546	1552	1578	1612	1504	1371

Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
4/29/2010	1304	1286	1283	1291	1326	1421	1616	1734	1733	1717	1712	1704	1670	1634	1602	1590	1587	1597	1596	1591	1633	1650	1533	1397
4/30/2010	1319	1287	1278	1283	1312	1395	1586	1713	1724	1709	1692	1662	1619	1594	1558	1530	1516	1505	n/a	n/a	n/a	n/a	n/a	1391
5/1/2010	1318	1283	1270	1275	1291	1342	1415	1489	1557	1596	1603	1585	1540	1499	1478	1460	1452	1467	1474	1463	1505	1544	1474	1384
5/2/2010	1314	1250	1232	1231	1244	1280	1334	1383	1433	1461	1469	1446	1423	1391	1360	1347	1346	1365	1375	1388	1435	1496	1406	1271
5/3/2010	1193	1158	1148	1151	1185	1284	1483	1616	1653	1658	1665	1675	1659	1633	1615	1596	1591	1589	1575	1565	1588	1620	1515	1386
5/4/2010	1328	1334	1335	1351	1389	1492	1686	1779	1753	1743	1731	1706	1674	1645	1610	1569	1560	1552	1543	1541	1582	1648	1553	1415
5/5/2010	1343	1318	1312	1315	1334	1421	1605	1721	1740	1744	1718	1711	1691	1664	1659	1650	1656	1639	1631	1624	1668	1726	1609	1506
5/6/2010	1428	1403	1382	1387	1421	1522	1718	1807	1782	1748	1727	1711	1681	1650	1619	1599	1590	1587	1573	1557	1572	1620	1542	1431
5/7/2010	1370	1347	1349	1368	1410	1507	1685	1763	1740	1726	1720	1700	1662	1641	1626	1610	1606	1598	1577	1558	1568	1628	1570	1475
5/8/2010	1400	1368	1354	1351	1367	1409	1474	1533	1621	1684	1692	1659	1615	1590	1575	1571	1572	1577	1573	1565	1574	1629	1578	1482
5/9/2010	1406	1359	1337	1337	1343	1377	1429	1493	1575	1605	1599	1564	1538	1508	1483	1473	1478	1494	1499	1517	1545	1591	1514	1394
5/10/2010	1322	1282	1276	1285	1321	1413	1589	1712	1746	1774	1797	1815	1811	1786	1767	1748	1756	1775	1750	1706	1707	1731	1618	1493
5/11/2010	1423	1385	1363	1370	1397	1485	1665	1767	1759	1743	1748	1728	1697	1672	1645	1626	1611	1599	1582	1554	1562	1609	1524	1396
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11/18/2010	1295	1262	1244	1241	1267	1356	1534	1674	1661	1644	1629	1613	1591	1579	1557	1567	1613	1720	1749	1725	1685	1606	1490	1377
11/19/2010	1312	1291	1285	1292	1326	1414	1593	1733	1739	1729	1723	1702	1676	1658	1651	1655	1690	1770	1774	1727	1669	1621	1544	1455
11/20/2010	1375	1335	1315	1308	1319	1370	1443	1538	1622	1672	1689	1664	1616	1580	1557	1557	1596	1720	1761	1728	1692	1641	1568	1489
11/21/2010	1426	1397	1389	1392	1409	1444	1510	1606	1682	1715	1722	1724	1721	1711	1693	1692	1720	1837	1862	1828	1789	1721	1608	1491
11/22/2010	1427	1405	1397	1406	1446	1538	1701	1818	1817	1809	1797	1799	1782	1776	1774	1789	1835	1943	1974	1943	1904	1822	1684	1549
11/23/2010	1470	1440	1433	1439	1478	1532	1707	1843	1870	1888	1888	1861	1843	1840	1851	1867	1919	2055	2115	2089	2046	1980	1876	1766
11/24/2010	1698	1681	1666	1682	1730	1814	1944	2098	2146	2126	2078	2034	1987	1955	1889	1898	1957	2083	2139	2120	2088	2035	1946	1847
11/25/2010	1786	1751	1754	1764	1790	1839	1912	1999	2068	2086	2068	2027	1935	1825	1750	1723	1745	1838	1875	1876	1849	1814	1741	1661
11/26/2010	1608	1595	1593	1601	1634	1697	1775	1854	1880	1858	1823	1792	1760	1738	1724	1729	1779	1915	1942	1915	1871	1810	1734	1656

Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
11/27/2010	1592	1540	1519	1501	1504	1539	1598	1669	1739	1810	1832	1820	1796	1757	1723	1719	1766	1868	1886	1850	1810	1756	1669	1578
11/28/2010	1514	1479	1469	1479	1490	1538	1614	1707	1773	1794	1772	1739	1716	1696	1682	1693	1745	1903	1965	1947	1907	1822	1709	1603
11/29/2010	1550	1541	1551	1580	1639	1749	1946	2092	2064	2001	1944	1882	1819	1768	1737	1734	1793	1987	2082	2079	2061	1980	1848	1728
11/30/2010	1672	1654	1654	1666	1709	1806	1992	2121	2084	2049	2014	1975	1949	1928	1917	1934	1982	2095	2118	2084	2035	1941	1803	1668

Table 22.2 Continued (2011 data)

Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
4/1/2011	1125	1104	1089	1089	1115	1191	1349	1482	1486	1465	1454	1431	1403	1387	1372	1351	1342	1343	1333	1331	1402	1393	1311	1189
4/2/2011	1290	1072	1060	1051	1054	1085	1147	1230	1323	1430	1478	1471	1451	1426	1399	1386	1394	1410	1409	1423	1507	1519	1440	1348
4/3/2011	1250	1261	1244	1250	1271	1311	1384	1470	1523	1563	1539	1500	1473	1430	1384	1352	1351	1363	1376	1399	1519	1542	1441	1317
4/4/2011	1192	1240	1245	1251	1286	1385	1590	1721	1713	1689	1662	1628	1570	1552	1521	1495	1487	1501	1517	1520	1576	1537	1404	1267
4/5/2011	1259	1165	1151	1154	1182	1268	1459	1605	1611	1620	1627	1611	1578	1543	1511	1491	1480	1482	1478	1476	1559	1569	1455	1326
4/6/2011	1271	1238	1243	1263	1307	1413	1622	1745	1717	1677	1632	1591	1557	1538	1506	1480	1478	1498	1534	1559	1610	1590	1463	1338
4/7/2011	1305	1245	1233	1242	1282	1370	1575	1721	1715	1697	1669	1621	1575	1547	1522	1500	1481	1486	1482	1505	1592	1595	1486	1371
4/8/2011	1301	1284	1282	1294	1336	1435	1627	1753	1736	1714	1683	1645	1594	1552	1513	1490	1481	1477	1462	1468	1540	1547	1476	1372
4/9/2011	1279	1268	1256	1252	1267	1311	1397	1488	1559	1607	1605	1567	1510	1454	1406	1379	1376	1383	1374	1375	1459	1492	1427	1342
4/10/2011	1163	1249	1240	1246	1267	1310	1383	1454	1507	1509	1483	1444	1412	1374	1342	1322	1318	1342	1364	1375	1444	1459	1353	1232
4/11/2011	1194	1141	1133	1143	1178	1272	1474	1600	1592	1578	1562	1540	1513	1492	1464	1442	1455	1474	1471	1471	1523	1523	1395	1261
4/12/2011	1165	1174	1182	1196	1235	1349	1560	1676	1646	1592	1541	1499	1463	1436	1413	1386	1368	1358	1355	1360	1441	1472	1363	1236
4/13/2011	1268	1143	1142	1153	1191	1285	1488	1618	1607	1591	1580	1566	1542	1530	1508	1500	1503	1529	1529	1497	1556	1561	1451	1332
4/14/2011	1271	1248	1249	1266	1308	1416	1639	1750	1704	1658	1617	1575	1540	1510	1478	1455	1439	1435	1439	1450	1538	1561	1451	1333
4/15/2011	1211	1249	1239	1248	1282	1373	1557	1666	1654	1621	1588	1550	1503	1468	1436	1422	1423	1432	1434	1429	1473	1467	1382	1282
4/16/2011	1135	1168	1150	1146	1157	1198	1275	1348	1410	1433	1423	1394	1358	1327	1301	1289	1288	1309	1316	1336	1382	1377	1302	1210
4/17/2011	1114	1088	1081	1082	1084	1106	1169	1244	1324	1362	1365	1346	1334	1313	1288	1276	1287	1322	1341	1358	1424	1418	1314	1189
4/18/2011	1266	1084	1077	1082	1114	1209	1406	1546	1570	1587	1586	1571	1544	1509	1475	1445	1432	1430	1439	1444	1518	1551	1444	1322
4/19/2011	1253	1247	1251	1262	1308	1417	1634	1730	1675	1629	1595	1555	1515	1486	1456	1431	1414	1410	1406	1412	1496	1550	1446	1318
4/20/2011	1214	1234	1241	1255	1296	1402	1600	1705	1687	1653	1621	1576	1545	1520	1500	1493	1502	1509	1508	1499	1532	1541	1424	1292
4/21/2011	1296	1183	1175	1173	1202	1294	1481	1598	1610	1611	1603	1605	1561	1544	1514	1492	1479	1474	1464	1459	1538	1586	1480	1365
4/22/2011	1218	1266	1264	1276	1313	1412	1611	1702	1662	1597	1548	1504	1454	1418	1383	1357	1336	1323	1301	1291	1363	1435	1380	1282
4/23/2011	1147	1195	1196	1208	1237	1293	1381	1453	1491	1489	1437	1385	1338	1297	1268	1248	1242	1252	1249	1243	1300	1372	1318	1225
4/24/2011	1094	1114	1111	1122	1143	1191	1268	1338	1406	1422	1379	1335	1320	1283	1237	1207	1189	1197	1218	1256	1322	1355	1266	1157
4/25/2011	1220	1065	1064	1074	1109	1207	1400	1528	1559	1573	1581	1573	1544	1533	1515	1476	1475	1478	1471	1471	1538	1533	1418	1287
4/26/2011	1256	1207	1220	1231	1271	1375	1585	1686	1664	1633	1613	1599	1567	1541	1501	1493	1480	1471	1472	1454	1506	1562	1457	1327
4/27/2011	1165	1237	1241	1255	1294	1401	1607	1683	1631	1609	1566	1534	1508	1490	1467	1445	1433	1424	1414	1405	1456	1510	1393	1261
4/28/2011	1327	1136	1129	1133	1160	1248	1441	1564	1574	1564	1572	1582	1577	1566	1554	1552	1551	1553	1552	1549	1580	1625	1519	1396

Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
4/29/2011	1301	1301	1294	1303	1335	1431	1628	1740	1737	1722	1706	1666	1621	1582	1541	1514	1496	1491	1477	1463	1505	1549	1475	1376
4/30/2011	1252	1275	1265	1272	1296	1356	1430	1481	1513	1535	1523	1495	1449	1408	1379	1361	1357	1367	1361	1367	1400	1472	1417	1320
5/1/2011	1175	1226	1226	1231	1247	1293	1365	1414	1450	1463	1449	1417	1392	1359	1334	1318	1320	1340	1350	1354	1399	1470	1384	1251
5/2/2011	1260	1154	1155	1177	1221	1330	1538	1635	1624	1621	1613	1595	1573	1562	1553	1534	1523	1534	1553	1560	1582	1590	1475	1341
5/3/2011	1311	1227	1219	1223	1261	1364	1563	1679	1692	1675	1659	1640	1608	1584	1568	1566	1549	1545	1526	1527	1568	1631	1528	1391
5/4/2011	1311	1277	1271	1278	1311	1414	1614	1704	1695	1681	1657	1619	1610	1588	1576	1559	1550	1549	1550	1541	1570	1645	1535	1393
5/5/2011	1332	1277	1258	1264	1300	1409	1596	1691	1700	1692	1684	1676	1658	1651	1650	1643	1644	1632	1623	1611	1634	1685	1582	1432
5/6/2011	1365	1285	1259	1250	1264	1343	1505	1621	1672	1688	1689	1678	1659	1658	1647	1630	1625	1617	1604	1597	1626	1648	1573	1456
5/7/2011	1291	1314	1290	1275	1281	1310	1366	1427	1515	1569	1578	1569	1551	1523	1502	1482	1479	1487	1489	1489	1522	1553	1483	1376
5/8/2011	1228	1244	1216	1201	1197	1217	1260	1327	1418	1485	1509	1489	1468	1438	1408	1384	1380	1389	1395	1400	1428	1501	1427	1301
5/9/2011	1293	1195	1197	1209	1249	1351	1546	1676	1703	1709	1697	1682	1654	1627	1597	1580	1576	1580	1576	1560	1572	1605	1498	1370
5/10/2011	1219	1267	1243	1238	1268	1361	1544	1622	1621	1589	1570	1566	1543	1532	1513	1505	1500	1501	1490	1478	1487	1543	1449	1309
5/11/2011	1250	1185	1173	1182	1219	1315	1476	1557	1561	1588	1555	1555	1544	1538	1533	1530	1535	1538	1538	1523	1535	1602	1505	1346
5/12/2011	1290	1196	1167	1160	1177	1258	1411	1513	1537	1561	1584	1599	1604	1624	1632	1638	1650	1658	1648	1630	1621	1667	1566	1398
5/13/2011	1373	1237	1208	1196	1209	1275	1405	1515	1566	1597	1619	1632	1641	1660	1677	1698	1722	1733	1716	1671	1670	1691	1608	1468
5/14/2011	1322	1312	1275	1238	1227	1256	1293	1357	1451	1528	1555	1572	1599	1618	1635	1651	1638	1633	1611	1586	1565	1578	1511	1405
5/15/2011	1277	1266	1235	1221	1212	1232	1249	1303	1397	1466	1495	1504	1507	1495	1483	1484	1498	1514	1537	1548	1568	1574	1471	1347
5/16/2011	1370	1242	1231	1238	1269	1373	1567	1690	1722	1748	1756	1735	1709	1682	1646	1614	1605	1607	1610	1604	1609	1658	1574	1440
5/17/2011	1363	1327	1312	1312	1344	1442	1617	1716	1735	1726	1714	1694	1676	1664	1653	1645	1641	1638	1635	1637	1652	1681	1589	1450
5/18/2011	1350	1324	1315	1311	1337	1416	1579	1717	1745	1720	1723	1717	1691	1675	1653	1641	1634	1633	1627	1622	1632	1669	1568	1437
5/19/2011	1320	1305	1287	1277	1292	1378	1534	1659	1687	1684	1676	1667	1656	1644	1633	1616	1607	1603	1597	1593	1595	1643	1569	1418
5/20/2011	1363	1270	1246	1229	1240	1317	1455	1576	1638	1654	1660	1663	1658	1662	1655	1656	1653	1650	1639	1626	1610	1645	1598	1466
5/21/2011	1345	1305	1273	1246	1243	1273	1321	1404	1502	1562	1591	1609	1612	1613	1614	1617	1621	1618	1602	1594	1592	1617	1551	1438
5/22/2011	1284	1297	1274	1249	1242	1256	1272	1338	1435	1496	1523	1532	1548	1536	1525	1520	1533	1558	1569	1566	1562	1604	1529	1375
5/23/2011	1365	1237	1214	1203	1221	1299	1452	1592	1663	1695	1713	1720	1719	1715	1705	1692	1683	1690	1690	1671	1678	1704	1606	1457
5/24/2011	1364	1325	1303	1292	1316	1403	1559	1682	1703	1712	1711	1703	1694	1681	1648	1642	1637	1632	1633	1621	1617	1662	1602	1456
5/25/2011	1394	1318	1297	1284	1307	1398	1533	1651	1698	1711	1730	1721	1714	1710	1708	1705	1704	1702	1710	1722	1721	1726	1623	1483
5/26/2011	1365	1358	1335	1320	1334	1411	1558	1676	1713	1717	1716	1705	1684	1668	1652	1634	1617	1599	1581	1572	1580	1634	1574	1447
5/27/2011	1363	1314	1296	1289	1310	1380	1511	1631	1688	1720	1730	1715	1679	1653	1651	1621	1595	1582	1593	1576	1545	1579	1542	1444
5/28/2011	1305	1323	1303	1291	1296	1331	1373	1438	1510	1562	1567	1550	1529	1501	1484	1479	1476	1483	1487	1480	1489	1522	1473	1383

Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
5/29/2011	1190	1264	1240	1230	1231	1261	1302	1354	1420	1457	1458	1444	1420	1384	1357	1339	1348	1348	1334	1336	1352	1393	1351	1257
5/30/2011	1145	1153	1137	1128	1139	1184	1229	1287	1364	1427	1466	1472	1444	1405	1377	1362	1361	1373	1376	1372	1379	1434	1373	1233
5/31/2011	1256	1106	1091	1093	1124	1205	1351	1486	1557	1584	1595	1594	1577	1565	1563	1565	1546	1543	1542	1530	1536	1572	1500	1352
6/1/2011	1343	1206	1179	1168	1180	1252	1374	1493	1556	1589	1611	1624	1634	1625	1618	1606	1601	1602	1601	1591	1602	1634	1553	1424
6/2/2011	1438	1320	1298	1285	1294	1371	1503	1638	1718	1758	1773	1781	1751	1725	1700	n/a	1669	1666	1660	1656	1664	1713	1655	1532
6/3/2011	1441	1363	1338	1325	1339	1416	1543	1662	1697	1712	1712	1718	1706	1694	1689	1686	1672	1657	1647	1651	1648	1688	1662	1542
6/4/2011	1456	1389	1350	1335	1329	1361	1412	1505	1587	1645	1655	1670	1669	1670	1674	1673	1685	1704	1703	1699	1699	1727	1691	1560
6/5/2011	1447	1393	1347	1324	1316	1326	1330	1391	1487	1550	1584	1608	1627	1638	1665	1679	1714	1767	1799	1789	1771	1788	1725	1568
6/6/2011	1478	1373	1334	1316	1324	1385	1495	1640	1760	1829	1897	1936	1937	1919	1890	1856	1842	1845	1835	1801	1789	1812	1715	1567
6/7/2011	1434	1421	1378	1354	1360	1416	1528	1644	1712	1747	1763	1771	1770	1762	1737	1731	1725	1726	1737	1732	1728	1749	1703	1546
6/8/2011	1419	1373	1333	1316	1324	1377	1477	1594	1679	2478	1831	1758	1761	1754	1740	1733	1719	1716	1712	1681	1683	1700	1645	1510
6/9/2011	1436	1376	1348	1329	1338	1405	1516	1635	1701	1742	1757	1761	1748	1743	1727	1714	1697	1698	1697	1694	1688	1708	1677	1537
6/10/2011	1437	1385	1341	1325	1331	1382	1472	1602	1671	1716	1739	1764	1767	1770	1761	1743	1710	1697	1677	1667	1664	1685	1654	1543
6/11/2011	1445	1375	1347	1317	1316	1348	1374	1460	1553	1629	1660	1668	1668	1668	1671	1679	1677	1682	1675	1668	1660	1683	1636	1529
6/12/2011	1390	1383	1343	1325	1314	1331	1334	1388	1474	1542	1588	1613	1624	1619	1618	1629	1656	1686	1702	1694	1672	1708	1655	1500
6/13/2011	1526	1329	1297	1287	1298	1362	1478	1613	1719	1791	1833	1859	1867	1880	1865	1869	1880	1889	1888	1890	1874	1874	1823	1662
6/14/2011	1580	1458	1421	1400	1401	1457	1557	1692	1787	1846	1886	1902	1904	1919	1934	1942	1943	1950	1981	1966	1942	1942	1885	1706
6/15/2011	1596	1508	1467	1438	1444	1499	1591	1739	1831	1882	1915	1935	1942	1930	1921	1918	1896	1895	1888	1874	1849	1874	1831	1700
6/16/2011	1645	1544	1499	1483	1494	1561	1657	1789	1880	1939	1971	1977	1973	1985	1975	1967	1943	1925	1919	1916	1922	1950	1906	1759
6/17/2011	1696	1593	1556	1534	1533	1585	1692	1795	1877	1937	1973	1986	1982	1983	1984	1984	1989	1995	2002	1996	1975	1984	1948	1810
6/18/2011	1583	1625	1579	1551	1532	1552	1581	1672	1785	1863	1898	1919	1921	1909	1888	1871	1864	1868	1860	1837	1839	1862	1804	1675
6/19/2011	1481	1526	1486	1468	1464	1476	1481	1544	1629	1687	1723	1725	1720	1705	1695	1697	1710	1713	1711	1709	1711	1736	1715	1582
6/20/2011	1747	1425	1393	1385	1401	1466	1577	1731	1847	1921	1961	1995	2015	2036	2056	2071	2080	2108	2139	2141	2122	2115	2056	1879
6/21/2011	1889	1667	1614	1582	1573	1620	1699	1826	1937	2030	2093	2145	2191	2224	2262	2307	2332	2369	2406	2405	2380	2337	2252	2053
6/22/2011	1957	1787	1718	1670	1661	1704	1797	1940	2067	2171	2251	2337	2407	2483	2555	2612	2657	2671	2649	2604	2541	2476	2333	2113
6/23/2011	1941	1869	1806	1745	1726	1766	1841	1994	2147	2255	2345	2424	2471	2516	2569	2608	2630	2633	2622	2560	2483	2406	2293	2089
6/24/2011	1870	1839	1778	1736	1716	1746	1812	1943	2051	2138	2180	2207	2212	2220	2227	2236	2240	2254	2257	2237	2209	2183	2148	1991
6/25/2011	1824	1794	1739	1703	1680	1686	1699	1802	1909	1992	2035	2058	2058	2067	2088	2116	2136	2151	2152	2129	2106	2112	2076	1939
6/26/2011	1730	1755	1697	1661	1637	1640	1630	1698	1793	1864	1921	1957	1987	2004	2026	2056	2101	2139	2158	2137	2085	2075	2016	1848
6/27/2011	2077	1668	1633	1617	1618	1666	1758	1898	2017	2112	2187	2247	2315	2380	2450	2525	2578	2630	2672	2676	2640	2581	2466	2250

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D. Reading: Simplot
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Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
6/28/2011	2121	1979	1908	1855	1836	1871	1947	2091	2234	2354	2452	2544	2628	2682	2737	2786	2817	2828	2843	2819	2744	2652	2511	2283
6/29/2011	2021	2014	1943	1894	1873	1902	1968	2111	2224	2318	2371	2415	2413	2408	2411	2442	2471	2488	2478	2452	2420	2388	2330	2158
6/30/2011	2003	1934	1884	1843	1818	1849	1931	2062	2154	2223	2297	2354	2370	2398	2417	2436	2437	2452	2477	2467	2430	2393	2329	2147
10/1/2011	1379	1393	1361	1340	1335	1353	1403	1468	1551	1627	1671	1716	1779	1835	1889	1923	1958	1980	1948	1910	1870	1759	1619	1473
10/2/2011	1287	1326	1291	1271	1263	1273	1302	1337	1399	1499	1561	1594	1642	1679	1718	1744	1786	1819	1793	1788	1772	1664	1514	1375
10/3/2011	1336	1242	1220	1207	1224	1296	1458	1581	1598	1641	1685	1721	1740	1782	1819	1856	1873	1880	1864	1871	1851	1723	1570	1431
10/4/2011	1256	1277	1251	1230	1241	1314	1478	1611	1620	1625	1634	1637	1622	1617	1606	1592	1589	1584	1591	1634	1648	1573	1450	1330
10/5/2011	1223	1219	1192	1180	1192	1262	1417	1556	1579	1598	1607	1609	1590	1574	1555	1550	1552	1564	1569	1590	1582	1506	1395	1290
10/6/2011	1266	1185	1170	1167	1189	1260	1409	1549	1594	1626	1648	1656	1638	1627	1618	1613	1618	1627	1649	1676	1657	1579	1461	1343
10/7/2011	1212	1223	1205	1196	1209	1273	1403	1523	1560	1589	1602	1589	1559	1529	1505	1481	1475	1486	1489	1501	1492	1446	1374	1282
10/8/2011	1155	1169	1152	1147	1154	1189	1260	1340	1389	1415	1409	1384	1355	1331	1315	1310	1317	1333	1346	1408	1427	1377	1301	1220
10/9/2011	1116	1120	1110	1109	1121	1153	1215	1291	1352	1385	1378	1355	1346	1325	1312	1306	1317	1342	1375	1458	1470	1400	1285	1178
10/10/2011	1170	1088	1085	1095	1127	1205	1370	1493	1497	1501	1500	1500	1489	1486	1483	1491	1496	1522	1557	1592	1567	1489	1354	1237
10/11/2011	1143	1134	1119	1117	1135	1214	1382	1507	1503	1487	1480	1468	1458	1458	1446	1425	1420	1421	1428	1495	1512	1444	1323	1210
10/12/2011	1135	1118	1110	1111	1139	1232	1423	1567	1550	1513	1487	1470	1447	1431	1407	1403	1408	1412	1426	1495	1506	1438	1315	1207
10/13/2011	1135	1111	1107	1117	1145	1234	1405	1546	1536	1507	1491	1475	1452	1444	1441	1431	1428	1427	1427	1485	1494	1427	1319	1207
10/14/2011	1127	1097	1086	1086	1105	1177	1335	1474	1472	1459	1452	1440	1421	1420	1418	1415	1417	1412	1401	1452	1443	1390	1306	1208
10/15/2011	1107	1070	1051	1040	1054	1086	1160	1251	1324	1368	1374	1362	1351	1339	1329	1321	1316	1331	1339	1400	1381	1336	1260	1176
10/16/2011	1067	1070	1050	1043	1048	1069	1115	1184	1259	1327	1366	1375	1359	1327	1325	1328	1360	1403	1444	1493	1458	1367	1248	1126
10/17/2011	1156	1059	1052	1049	1082	1175	1370	1512	1532	1509	1494	1468	1441	1422	1405	1388	1386	1392	1417	1508	1509	1439	1320	1210
10/18/2011	1146	1135	1130	1134	1162	1257	1467	1614	1592	1554	1516	1482	1449	1452	1424	1410	1409	1412	1418	1500	1504	1444	1325	1203
10/19/2011	1153	1109	1096	1100	1145	1241	1430	1573	1568	1545	1530	1498	1460	1437	1422	1411	1406	1415	1434	1530	1521	1456	1334	1221
10/20/2011	1142	1129	1124	1130	1164	1258	1450	1601	1585	1551	1521	1490	1462	1454	1451	1434	1429	1425	1445	1527	1515	1447	1327	1212
10/21/2011	1141	1113	1095	1091	1111	1187	1356	1510	1521	1504	1484	1462	1434	1416	1407	1394	1389	1379	1386	1448	1432	1382	1302	1210
10/22/2011	1138	1107	1090	1086	1099	1139	1216	1318	1383	1427	1422	1392	1360	1339	1314	1306	1302	1327	1364	1438	1421	1365	1284	1203
10/23/2011	1099	1100	1087	1082	1090	1123	1188	1274	1350	1378	1370	1353	1342	1324	1314	1314	1331	1372	1411	1492	1464	1385	1265	1162
10/24/2011	1210	1071	1058	1059	1087	1177	1369	1523	1538	1531	1526	1498	1473	1454	1433	1421	1421	1445	1505	1583	1563	1496	1377	1263
10/25/2011	1276	1195	1191	1198	1233	1335	1549	1720	1724	1685	1643	1590	1539	1501	1469	1449	1449	1472	1530	1635	1629	1568	1447	1334
10/26/2011	1269	1259	1253	1267	1304	1406	1614	1770	1759	1706	1657	1612	1564	1524	1492	1464	1458	1471	1522	1626	1632	1576	1455	1338
10/27/2011	1295	1242	1231	1242	1280	1384	1587	1747	1756	1722	1678	1622	1564	1523	1489	1460	1454	1462	1522	1615	1613	1560	1460	1352

Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
10/28/2011	1246	1273	1273	1280	1315	1411	1595	1749	1759	1729	1692	1642	1569	1515	1477	1449	1443	1459	1501	1547	1528	1492	1410	1315
10/29/2011	1206	1208	1190	1186	1197	1239	1312	1400	1484	1527	1517	1477	1429	1383	1355	1338	1339	1356	1396	1473	1464	1410	1336	1262
10/30/2011	1143	1181	1182	1186	1199	1237	1306	1401	1476	1483	1461	1428	1397	1364	1336	1325	1336	1369	1429	1511	1493	1427	1319	1213
10/31/2011	1227	1112	1102	1106	1138	1225	1411	1565	1586	1573	1560	1534	1504	1471	1444	1425	1423	1423	1449	1484	1483	1475	1393	1285

Exhibit 504
GNR-E-11-03
D. Reading: Simplot
Exergy, Clearwater
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REQUEST FOR PRODUCTION NO. 23: Reference the Direct Testimony of Tessia Park, p. 24, describing the minimum base generation (300 MW thermal, 817 MW hydro, and 50 MW non-intermittent PURPA) to be near 1,100 MW. Please explain why Idaho Power could not plan for an expected light loading period coinciding with possible excess QF generation by un-designating the network resource status of a specified quantity of this base generation, and using its fast-ramping, remaining Hells Canyon capacity to serve load in the event that intermittent QF generation did not occur as predicted.

RESPONSE TO REQUEST FOR PRODUCTION NO. 23: The particular network resource that is undesignated must be used to supply energy for a sourced sale. If Idaho Power undesignates and sells power from a baseload resource, that resource must be able to supply the system sale. In order to sell firm resources into the market, Idaho Power limits the amount of generation from the baseload resources to 50 percent of that resource's available generation capacity to ensure sufficient generation exists from that facility to supply the firm sale and to comply with Idaho Power's Open Access Transmission Tariff ("OATT"). Additionally, Hells Canyon is limited in ramping ability due to downstream river level changes of one foot per hour. This severely limits the ability for Hells Canyon units to ramp to support large deviations in outflow. Idaho Power sets aside capacity in the pre-schedule or day ahead to cover reserve requirements and meet load demands. Idaho Power's procedures require the Company to sell or buy energy to balance the system in pre-schedule based on generation and load forecasts, this takes into account wind forecasts, as well as limitations on hydro stream flows and the ability to ensure compliance with FERC requirements and the OATT.

The response to this Request was prepared by Tessia Park, Director Load Serving Operations, Idaho Power Company, in consultation with Donovan E. Walker, Lead Counsel, Idaho Power Company.

REQUEST FOR PRODUCTION NO. 42: Reference the Direct Testimony of Tessia Park, page 11, containing the following dispatch costs: Langley Gulch ($22/MWh), coal generators (generally below $30/MWh). These values are different from those provided for the hourly variable generation costs provided in the confidential attachment to Staff's Request No. 2. Please explain the discrepancy and provide the correct dispatch costs for each of the Company's gas and coal plants.

RESPONSE TO REQUEST FOR PRODUCTION NO. 42: In Tessia Park's testimony, the data stated for the dispatch costs of the Langley Gulch power plant and the coal generations were representative estimates. These dispatch costs were representative of average dispatch costs, not specific dispatch costs by resource as was the data provided in the Company's response to the Idaho Public Utilities Commission Staff's Production Request No. 2.

The response to this Request was prepared by Tessia Park, Director of Load Serving Operations, Idaho Power Company, in consultation with Donovan E. Walker, Lead Counsel, Idaho Power Company.

REQUEST NO. 5: The direct testimony of Tessia Park discusses generally the low loading conditions when the proposed Schedule 74 might require curtailment, and describes a representative example on pages 23-24. Has Idaho Power conducted any analysis or studies to attempt to estimate the frequency, duration, and magnitude of curtailments that might be invoked in the future or that would have been invoked in the past if its proposed Schedule 74 was in place? Please provide a copy of any analysis or studies. If no analysis or studies have been done, please provide estimates if possible.

RESPONSE TO REQUEST NO. 5: Idaho Power has not conducted an analysis or study to estimate the frequency, duration, or magnitude of curtailments that might have been invoked or would be invoked in the future under the proposed Schedule 74. Idaho Power estimates that curtailments under Schedule 74 would occur during periods of low load and be more likely during high water conditions, such as in the spring months, and during periods of low market prices, which are indicative of there being no market demand for Idaho Power's surplus energy.

As part of determining the hourly incremental cost in the alternate IRP methodology proposed in Company witness Bokenkamp's testimony, there are a small number of hours each year where the hourly incremental cost is zero. While these zero-cost hours are used in the calculation of the monthly average heavy load and light load price, they do not estimate the amount of curtailment expected under Schedule 74. During the zero-cost hours, Idaho Power would still be accepting delivery of QF generation, and paying the project the appropriate monthly average heavy or light load price. Similar conditions tend to exist (low load and high water) at times when the hourly incremental price is zero and curtailment may be necessary under Schedule 74; however, they are not synonymous.

The response to this Request was prepared by Tessia Park, Load Serving Operations Director, Idaho Power Company, in consultation with Donovan E. Walker, Lead Counsel, Idaho Power Company.

REQUEST NO. 6: If Idaho Power's proposed Schedule 74 were to be approved by the Commission and QFs were curtailed during certain low load conditions, would the avoided cost rates computed based on Aurora analysis be impacted? Has Idaho Power conducted any Aurora analysis to compute avoided cost rates under an assumption that QFs could be curtailed under certain low load conditions?

RESPONSE TO REQUEST NO. 6: Avoided cost rates computed by AURORA are set for the duration of the contract based upon the QF's estimated hourly generation profile for a period of one year, and this computation is not impacted by possible curtailment. However, if Idaho Power must pay for curtailment, it must also be able to recover such payments. If Idaho Power may curtail without payment, no adjustment to avoided costs through the integration charge is necessary.

In its updated wind integration study, the Company has been careful to not include any costs associated with curtailment in the wind integration cost analysis. The AURORA model used by Idaho Power to determine the avoided cost of energy is not capable of modeling wind curtailment and therefore curtailment is not valued in the pricing proposed by Idaho Power. Because a certain amount of curtailment is anticipated in the modeling performed as part of the wind integration study, Idaho Power does not believe it would be appropriate to account for curtailment in the avoided cost pricing model.

The response to this Request was prepared by M. Mark Stokes, Power Supply Planning Manager, Idaho Power Company, in consultation with Donovan E. Walker, Lead Counsel, Idaho Power Company.

Service Date: September 13, 2011

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

IN THE MATTER OF the Petition of NorthWestern Energy for a Declaratory Ruling on the Applicability of 18 C.F.R. § 292.304(f) and ARM § 38.5.1903(1) to Contracts with Qualifying Facilities	)))))	REGULATORY DIVISION DOCKET NO. D2011.7.57 ORDER NO. 7172

ORDER REJECTING NORTHWESTERN ENERGY'S REQUESTED DECLARATORY RULING THAT ITS PROPOSED QUALIFYING FACILITY CURTAILMENT PROVISION IS CONSISTENT WITH 18 CFR SEC. 292 AND ARM 38.5.1903(1)

INTRODUCTION

1. On July 8, 2011, the Montana Public Service Commission ("Commission") received the Petition of NorthWestern Energy ("NWE") seeking the Commission's declaration that the "curtailment" language that NWE proposes to include in new Qualifying Facility ("QF") contracts is consistent with governing state and federal administrative rules. ARM § 38.5.1903(1) and 18 CFR 292.304(f).

2. On July 14, 2011, the Commission issued a public notice of the filing of the Petition and invited concerned members of the public to file comments by August 1, 2011, while allowing NWE and others until August 15, 2011 to file reply comments.

3. Initial comments were received from New Moon Ranch, LLC; Hydrodynamics, Inc.; Sagebrush Energy, LLC; the Montana Department of Natural Resources and Conservation—State Water Projects Bureau; Two Dot Wind Farm; Natural Resources Defense Council; Fairfield Wind LLC, Greenfield Wind LLC and Front Range Wind LLC; United Materials of Great Falls and Exergy Development Group; Renewable Northwest Project; and Russ Bentley. In these comments, NWE's proposed curtailment language received little or no support.

4. Reply comments and legal arguments were received from NWE. In its reply comments (which are discussed below), NWE argued that it alone, and not existing or potential QFs, should have been allowed to comment in this proceeding on the significant impact of the proposed curtailment language. NWE also argued that a host of generically-stated "problems" with the QF regulatory regime are the responsibility of this Commission.[1]

5. NWE argues in its Petition (pp. 1-2) that its obligation to purchase electricity from QFs produces surplus power situations that harm the interests of NWE and its customers in certain hours, and that this resulting surplus must be sold for less than the purchase price. To address this situation, NWE proposes curtailment language for its new QF contracts that would relieve it of its obligation to purchase QF output during "light load" hours. NWE's proposed remedy for this situation is the following language:

> No Obligation to Accept Energy: Northwestern shall not be obligated to accept or pay for Energy from Seller during any period in which, due to operational circumstances, the acceptance of Energy from Seller and Similarly-Situated Suppliers of energy to NorthWestern is expected to result in NorthWestern system costs greater than those which NorthWestern would incur if it did not accept such deliveries, including periods in which NorthWestern generated an equivalent amount of energy itself. For illustrative purposes only, and without limiting the circumstances under which NorthWestern might be relieved of the obligation to accept or pay for Energy from Seller under this section, an example of such a period is a period when NorthWestern would be forced to shut down a base load or intermediate load plant in order to accept deliveries of Energy from Seller and such base load or intermediate load plant could not then be restarted and brought up to its rated output to meet the next period's peak load and NorthWestern would consequently be required to utilize costly or less efficient generation with faster start-up or purchase higher-priced energy to meet the demand that could have been met by the base load or intermediate load plant but for such purchases from Seller. During periods in which NorthWestern is purchasing energy both from Seller and from Similarly-Situated Suppliers, the implementation of any curtailments of deliveries of energy is subject to the sole discretion of NorthWestern; provided, however, as between Seller and such Similarly-Situated

[1] "QFs view PURPA as creating an entitlement rather than a competitive opportunity. Some large projects are attempting to disaggregate into smaller projects that qualify for the standard offer rate. Furthermore, QFs do not recognize that intermittent resources are not the equivalent of resources that can be dispatched. Finally QFs seem to believe that retail customers should subsidize their projects regardless of cost and that they should not be held to the same commercial terms as other suppliers. Additionally, the Commission has substantially contributed to the problems. For its part, the Commission has failed to distinguish and establish QF rates that consider the availability of energy or capacity under peak periods, the expected reliability of the project, and the ability to dispatch the QF (among other factors), as required by 18 CFR Sec. 292.304(e)(2). In addition, the Commission has adopted administrative rules that are inconsistent with federal regulations; under preemption principles, where compliance with both is an impossibility, the federal regulation preempts the state regulation, and the state regulations are invalid." Reply Comments, p. 2.

Suppliers, such curtailments shall be made on a non-discriminatory basis in accordance with the NorthWestern Energy Curtailment Protocol attached hereto as Exhibit C.[2]

6. The federal and state regulations that NWE seeks to have interpreted as they may impact its ability to include the new curtailment language in its QF contracts are 18 C.F.R.§ 292.304(f) and ARM § 38.5.1903(1).

18 C.F.R.§ 292.304(f) provides:

> *Periods during which purchases not required.* (1) Any electric utility which gives notice pursuant to paragraph (f)(2) of this section will not be required to purchase electric energy or capacity during any period during which, due to operational circumstances, purchases from qualifying facilities will result in costs greater than those which the utility would incur if it did not make such purchases, but instead generated an equivalent amount of energy itself.
>
> (2) Any electric utility seeking to invoke paragraph (f)(1) of this section must notify, in accordance with applicable State law or regulation, each affected qualifying facility in time for the qualifying facility to cease the delivery of energy or capacity to the electric utility.
>
> (3) Any electric utility which fails to comply with the provisions of paragraph (f)(2) of this section will be required to pay the same rate for such purchase of energy or capacity as would be required had the period described in paragraph (f)(1) of this section not occurred.
>
> (4) A claim by an electric utility that such a period has occurred or will occur is subject to such verification by its State regulatory authority as the State regulatory authority determines necessary or appropriate, either before or after the occurrence.

ARM § 38.5.1903(1) provides:

> Each utility shall purchase any energy and capacity made available by a qualifying facility, except that a utility is not obligated to make purchases from an interconnected qualifying facility:
>
> (i) during system emergencies if such purchase would contribute to the emergency;
>
> (ii) as stipulated in the contract between the utility and the qualifying facility;
>
> (iii) if, due to operational circumstances, purchases from a qualifying facility will result in costs greater than those which the utility would incur if it did not make such purchases. This provision is only applicable in the case of light loading periods in which the utility must cut back base load generation in order to purchase the qualifying facility's production followed by an immediate need to utilize less efficient generating capacity to meet a sudden high peak. Any utility seeking to invoke this exception must notify each affected qualifying facility and the commission one month prior to the time it intends to invoke this provision. Failure to properly notify the qualifying facilities and the commission or incorrect identification of such a period will result in reimbursement to the qualifying facility by the utility in an amount equal to that amount due had the qualifying facility's production been purchased.

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[2] NWE did not include Exhibit C with its filing, although the Exhibit was attached to the filing of Hydrodynamics.

7. NWE asserts that the number of hours in which it experiences surpluses is increasing, stating:

> As NorthWestern enters into more PPAs with QFs, the occurrence of the operational circumstances described in the preceding paragraphs becomes more frequent and resulting effects potentially greater...Petition, p. 4.

NWE did not attempt to quantify the cost and rate impacts of these alleged conditions.

8. NWE argues that its proposed curtailment language conforms closely to the language of the federal regulation, that FERC has not rejected similar language in various dockets where contracts containing that language has been before that Commission (although that language was not directly addressed by FERC), and that no Montana cases compel the rejection of the language.

9. Rather than list the arguments of each of the commenters, the Commission will summarize the arguments that have been presented against the proposed curtailment language.

a. The relevant cost comparison under the CFR is between the QF price and the operating cost associated with curtailment plus the restart cost of a baseload unit. The CFR authorizes curtailment only for operation and not for economic reasons, and does not relieve the utility of its obligation to purchase QF output in the situation described by NWE.

b. The proposed language is too broad in scope and would confer excessive discretion on NWE to impose curtailments based on a range of economic circumstances. Further, it is not clear whether NWE would curtail its own generation so that all providers would be treated similarly.

c. The right under the proposed curtailment language to refuse to purchase QF output following notice to the QF is fundamentally at odds with the obligation to purchase embodied in the Public Utility Regulatory Policies Act of 1978 (PURPA) and state law. The proposed language would authorize economic curtailment when market prices are low, and the resulting uncertainty would prevent QF developers from arranging affordable financing. NWE's application for approval of the Spion Kop wind project (Docket No. D2011.5.41) provides that NWE would enter a PPA as buyer if the Commission declines to preapprove the project;

however, that PPA does not contain a parallel curtailment provision to that proposed here by NWE. The proposed language has no upper limit on the number of hours that curtailment could be imposed, rendering a QF's revenue stream something of a guessing game.

d. NWE argues that the governing federal and state regulations, adopted during a period of vertical integration, must be construed in light of today's circumstances, when NWE relies heavily on PPAs from a variety of sources. However, the context of both the FERC and PSC rules is clearly reduction and restart of baseload power units. If NWE wishes to see those rules adapted to its changed environment, its remedy is to pursue rulemaking rather than advocating strained interpretation of these regulations.

e. The proposed curtailment language is excessively broad and would allow NWE to curtail QF ouput at any time the QF cost exceeded that of power available from the market. The lack of an upper bound on the potential hours to be curtailed would make financing of a QF seeking to contract with NWE impossible. Clear guidelines are needed defining conditions such as "light load" and "sudden high peak," and, absent those guidelines, contracts now in negotiation should proceed without the disputed language. NWE has contracted for substantially more energy than it requires to serve its normal load. With 30 MW of new wind QFs having been added recently, the addition of another 20 MW that will take NWE to the Commission's 50 MW "cap" will hardly burden NWE's shareholders or its customers. NWE's reliance on California authority is misplaced; California's curtailment cases compare the cost of self-generation to the cost of QFs—there is no comparison to market purchases. Curtailment policy should apply equally to the utility and its resources that are supplied under PPAs and to QFs. Spion Kop, if it is approved, should live by the same rules NWE has proposed for other resources. QFs should be allowed to obligate themselves to a legally-enforceable obligation that does not include the arbitrary curtailment language; NWE's insistence on this provision prevents the QF from exercising that right.

f. NWE consistently attempts to limit its requirement under PURPA to purchase electricity from QFs; this filing is another effort to introduce uncertainty that will compound the difficulty already facing QFs in obtaining financing. NWE seeks to incorporate cost analysis for intermediate load plants, but that term is not defined in federal or state rules. While hydropower is much more predictable than the output of wind facilities, NWE's language would nonetheless extend operational limitations to that type of plant without justification.

g. In framing its rules FERC recognized that avoided costs would vary from time to time. NWE ignores that fact by picking a particular operational circumstance when avoided costs are low, and then seeks unbridled authority to curtail QFs during those hours. This approach finds no support in the language of PURPA, in the rules implementing PURPA, or in precedent. The term "operational circumstances" was intended to be narrowly construed to include the situation where baseload generation must be reduced and cannot be brought back to its former output level in a timely manner. The full scope of NWE's intent is not clear because its proposed curtailment language is so general in nature. Because of the uncertainty regarding application of the language, a QFs revenue stream will not be predictable.

h. In fact, one QF, Horseshoe Bend, accepted curtailment language very similar to that proposed by NWE in this case. That contract covers sales to NWE in the summer of 2011. In the month of July, NWE invoked curtailment in 50 separate hours, only a few of which would normally be considered "light load hours." NWE has not provided Horseshoe Bend with documentation of the basis for its curtailments. The NWE language is excessively broad and provides NWE with significant discretion, while providing QFs with no assurance that similarly-situated generators will be treated identically.

i. The proposed curtailment language allows NWE to curtail deliveries in its sole discretion so long as similarly situated suppliers are treated in a non-discriminatory nature. This provision would render NWE's purchase obligation under PURPA and under Montana law meaningless. Similar curtailment language sought by The Montana Power Co. was rejected by the Commission in 1983. Further, this Commission has held that relative rate certainty is essential. Future revenue streams must be predictable if new QF projects are to have access to capital. Finally, this issue must be resolved quickly if current federal programs that encourage QF development are to be available to developers, since projects must be substantially advanced in development in 2011 if federal subsidies are to be secured.

10. NWE's Reply to the Initial Comments of the QFs seeks to portray NWE as the protector of its customers. NWE acknowledges that those opposing the Petition forcefully present their interests and needs, but NWE believes that they ignore the delicate balance that must be achieved between QF interests and PURPA's requirements for consumer indifference. NWE is a voice for the utility's interests and also for its retail customers' interests. Reply, p. 3.

ANALYSIS

11. The heart of NWE's legal argument is that its proposed curtailment language is consistent with 18 CFR 292.304(f)(1).[3] This comparison is presented at pages 4 and 5 of the Reply. NWE relies on the parallel language of the two provisions which states that the purchase obligation can be avoided during periods when "operational circumstances" cause costs greater than those the purchasing utility would incur if not for the QF deliveries. However, in advancing this argument, NWE wholly ignores several key points. First, the preamble of the federal rule upon which NWE rests its case states that:

> This section was intended to deal with a certain condition which can occur during light loading periods. If a utility operating only base load units during those periods were forced to cut back output from the units in order to accommodate purchases from qualifying facilities, these base load units might not be able to increase their output level rapidly when system demand for power later increased. As a result, the utility would be required to utilize less efficient, higher cost units with faster start-up to meet the demand that would have been supplied by the less expensive base load unit had it been permitted to operate at a constant output. 45 Fed. Reg 12227 (Februrary 25, 1980)

The Commission's rule at issue contains language that closely parallels the FERC preamble. ARM § 38.5.1903(1), states that:

> (iii) if, due to operational circumstances, purchases from a qualifying facility will result in costs greater than those which the utility would incur if it did not make such purchases. This provision is only applicable in the case of light loading periods in which the utility must cut back base load generation in order to purchase the qualifying facility's production followed by an immediate need to utilize less efficient generating capacity to meet a sudden highpeak.

Therefore, the Commission concludes that there is no conflict between its rule and that of FERC. NWE's reading of the federal and state rules, and its proposed curtailment language, must be rejected. Even if the FERC's rule and its intent were as NWE wishes, the ARM clearly prohibits NWE's language. Further, federal law authorizes the State to adopt its own requirements in this area:

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[3] The language of the FERC regulation that NWE relies on reads as follows: "Any electric utility which gives notice pursuant to paragraph (f)(2) of this section will not be required to purchase electric energy or capacity during any period which, due to operational circumstances, purchases from qualifying facilities will result in costs greater than those which the utility would incur if it did not make such purchases, but instead generated an equivalent amount of energy itself."

> Beginning on or before the date one year after any rule is prescribed by the commission under subsection (a) of this section or revised under such subsection, each State regulatory authority shall, after notice and opportunity for public hearing, implement such rule (or revised rule) for each public utility for which it has ratemaking authority. 16 USC Sec. 824a-3(f)(1)

The Montana Legislature has authorized the Commission to "adopt rules further defining the criteria for qualifying small power production facilities, their cost-effectiveness, and other standards." Sec. 69-3-604, MCA.

12. In light of the foregoing, the Commission finds that NWE's proposed curtailment language is not authorized by state or federal law, and NWE is prohibited from demanding that new QFs with whom it is negotiating accept such language as a pre-condition of contracting with NWE for the sale of their output to the utility. If market conditions occasionally result in prices less than NWE's tariffed avoidable costs, that is not in itself a sign that the principle of consumer indifference is unlawfully being violated—no more than if a long-term acquisition of NWE's own were to result in a fixed-and-variable cost-per-unit which were higher than prices available on the spot market. Sec. 18 CFR 292.304(b)(5).

13. It is also important to note that NWE's QF tariffs make no provision for the reduction of purchase volumes for curtailments sought by the buyer. For example, NWE Schedule No. QF-1 provides that the specified purchase prices, Options 1 (a)-(c) provide that the full price will be paid for deliveries at "all hours"; Option 2(a) refer to purchases during "each hour", Option 2(b) refers to metered kWh delivered to the Utility; and Option 3 applies the purchase price to deliveries at "all hours." The Commission concludes that NWE is bound by the provisions of its tariffs, as well as State and Federal rules, as discussed above.

14. NWE's Reply Comments contain several arguments that warrant a response. NWE's critique of the Commission's system of QF regulation ignores NWE's obligation to advocate and support avoidable cost calculation methods and tariff rates with high quality evidence that will withstand critical scrutiny. If the avoided cost of intermittent resources is less than the rates contained in MPSC tariffs, NWE is not lacking in opportunities to prove that case. When NWE's electric power supply plans regularly include wind resources within the preferred portfolios, NWE is not advocating a limit on wind procurement. Indeed, NWE recently

advocated in Docket No. D2010.7.77 a separate rate for wind QFs of 10 MW or less. The Commission agrees with commenters that it is not clear why the "back up" PPA for Spion Kop (the contract under which NWE would secure wind if its own acquisition of the wind farm is rejected) does not contain a curtailment provision like that at issue here.

15. A sound approach to implementing PURPA is particularly important now as NWE transitions from a default supplier in a deregulated retail market to a vertically integrated utility with an electricity supply monopoly. PURPA requires a neutral playing field for qualifying facilities and facilities that NWE may prefer to own. So long as PURPA is law, the Commission will enforce it. While rejecting much of NWE's criticism of its approach to implementing PURPA, the Commission is open to working with NWE and others to improve that approach. To the extent NWE has ideas in this regard it should proactively offer them in its biennial QF tariff filings or petitions for rulemaking. These are the proper places for reform, not a petition for declaratory judgment seeking to extend an existing rule to a situation that clearly does not apply.

16. As to NWE's argument that comments of QFs should not have been solicited in this proceeding (Reply Comments, pp. 6-9), counsel for NWE is well aware that receipt of comments from interested parties in declaratory ruling proceedings has been the longstanding practice of the Commission. Presumably, the rule requiring the petitioner seeking a declaratory ruling to list "the name and address of any person known by petitioner to be interested in the requested declaratory ruling" does so precisely so that the views of those persons can be obtained. Sec. 1.3.227(2)(h), ARM. This practice was followed in a recent NWE declaratory ruling request involving the Turnbull Project. Docket No. D2009.11.151. Finally, the Commission, in designing its procedures, is obligated to

> ...include a method of affording interested persons reasonable opportunity to submit data, views, or arguments, orally or in written form, prior to making a final decision that is of significant interest to the public. Sec. 2-3-111, MCA.

The solicitation of comments from interested parties in this proceeding is necessary to comply with the Commission's statutory obligation to provide a meaningful opportunity for public participation as required by statute.

ORDER

The Commission rejcts NWE's proposed declaratory ruling that its proposed curtailment language is consistent with 18 C.F.R. §292.304(f) and ARM § 38.5.1903(1).

DONE AND DATED the 1st day of September 2011 by a vote of 3 to 2. Commissioners Gallagher and Molnar dissenting.

BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION.

TRAVIS KAVULLA, Chairman

Gail Gutsche

GAIL GUTSCHE, Vice Chair

W. A. GALLAGHER, Commissioner (Dissenting)

BRAD MOLNAR, Commissioner (Dissenting)

JOHN VINCENT, Commissioner

ATTEST:

Judy Scherer
for Aleisha Solem

Aleisha Solem
Commission Secretary

(SEAL)

NOTE: Any interested party may request the Commission to reconsider this decision. A motion to reconsider must be filed within ten (10) days. See ARM 38.2.4806.

Service Date: September 13, 2011

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISION
OF THE STAE OF MONTANA

IN THE MATTER OF the Petition of NorthWestern Energy for a Declaratory Ruling on the Applicability of 18 C.F.R. 292.304(f) and ARM 38.5.1903(1) to Contracts with Qualifying Facilities	)))))	REGULATORY DIVISION DOCKET NO. D2011.7.57 ORDER NO. 7172

DISSENT OF COMMISSIONER
BRADLEY A. MOLNAR TO ORDER NO. 7172

INTRODUCTION

On July 8, 2011, the Montana Public Service Commission (Commission) received a petition from NorthWestern Energy (NWE) seeking declaration of proposed curtailment language NWE proposes for new Qualifying Facility (QF) contracts. They offered ARM 38.5.1903(1) and C.F.R. 292.304(f) as proof of their capacity to include curtailment language.

On September 1, 2011, the Commission, without a public hearing, voted 3-2 to reject NWE's proposal to include in future QF contracts language giving the ability to curtail purchases when market conditions (including light load hours) are such that certain QF purchases are not necessary so the energy must be sold at a loss. This is a continuation of the Commission's economic assault on customers of regulated utilities. Using tortured logic the Commission has consistently ignored the plain wording of federal and state consumer protections designed to allow "market ready" small generators into the regulated market without consumer harm. I firmly believe those outside the narrow band of special interests profiting from below costs sales would agree this ruling ignores/defies various ARMs and laws in order to promote various industrial and political agendas.

ANALYSIS

One of the first issues was whether the various commenters should have been allowed to comment. I concur with staff; indeed they should be allowed to comment. However, their comments did not stick to the question of curtailment language but went to financing considerations. Unsupported/undocumented discussions on impacts on unnamed credit sources should never have been in our legal conclusions.

The only question is whether NWE "shall not be obligated to accept or pay for Energy from Seller during any period in which, due to operational circumstances, the acceptance of Energy from Seller and Similarly-Situated Suppliers of energy to NorthWestern is expected to result in NorthWestern system costs greater than those which NorthWestern would incur if it did not accept such deliveries…," as well as, is there a legal basis for or against the conclusion?

This is not difficult. In multiple dockets, final orders and discussions, Commission staff, Commissioners, and the Montana Consumer Counsel (which ignored this opportunity) have all alluded to the overarching PURPA dictate that while the goal is to provide an opportunity for small generators to sell their product consumers must be made "indifferent." This is referenced on P.6 Para 10 and denigrated away with the use of "occasionally" in lieu of the more accurate "predictably" which goes to the need for curtailment. Men of good heart could not argue that buy high/sell low (and stick consumers with the difference) comports to this mandate.

The referenced ARM 38.5.1903(1)(ii), clearly states that curtailment is allowed if stipulated in the contract, and 18 C.F.R. 292.304(f) seems to mirror the requested language in the NWE proposed language and gives all the authority needed without PSC preapproval. The request for a declaratory ruling seems beyond an abundance of caution and causes one to look for other rationale. ARM 38.5.8204(a) also speaks to this issue by clearly stating that "customers should be supplied with reliable, stably and reasonable priced (electricity) at the lowest long term price." After one notes that consumer indifference is our guide under federal and state policy one should note the lack of mandated concern for financial markets and access to federal subsidies. The mandate of "reliability" was addressed on page P.8 Para 12 where it was labeled an "unavoidable complexity" then deleted. The proposed language avoids much of the complexity.

ARM 38.5. 8219 plainly mandates the mitigation of risk through analysis of (d) competitive prices and (i) contract terms and conditions. This is plainly a mandate to NWE. The Commission is supposed to enforce ARM 38.5.8219, not ignore it. The Commission opted to shift the risk from QF financiers and QF developers to consumers. This is outrageous, undefendable and illegal.

The ARMs provide procedure to implement the law. MCA 69-8-419 instructs the utility at (2)(a) to provide adequate and reliable electricity supply service at the lowest long-term total cost, (c) identify and cost effectively manage and mitigate risks related to its obligation to provide electricity supply service, and (d) use a competitive procurement process whenever possible.

The Commission's 3-2 vote on the issue of economic curtailment is direction to NWE to violate federal and state laws and policies leading to extreme regulatory uncertainty and legal risk as NWE's legal obligations are not lifted by rogue Commission actions. Now that NWE has raised the issue they are obligated to achieve resolution.

GENERAL

The constant references to Spion Kop for justifications are a major concern. This order dealt strictly with curtailment language in future QF contracts. Spion Kop is not a QF so any analogies are immaterial as they are not covered in, nor is there a mandate from, PURPA. Rather it seems like childish finger pointing after a playground scuffle wherein justification seems to hinge on, "Oh yeah, how about him"; rather than a discussion of the point in controversy.

More importantly Spion Kop is a docketed matter. Arguably we have pre-approved non-curtailment language for Spion Kop before the hearing. Never during my tenure have we used a docketed item for a point of discussion outside the docket. Rather we have been consistently warned about discussing dockets or possible findings. Perhaps the entire Commission now needs to consider recusal on the Spion Kop docket.

On page nine Commissioner Kavulla once again uses the negative attention seeking device that NWE should have chosen a venue and time more to his personal preference. That seeking a declaratory ruling not fitting his unpublished time frame is somehow unjustified, worthy of his contempt and cause for denial.

Having read and reread the ARMs concerning the request for declaratory rulings I find zero references to preferences for "biennial QF tariff filings" or "petitions for rule makings." Nor are there any such challenges in the evidentiary record. There are only requirements for filings, not a list of mandates for venue shopping prior to a request for a declaratory ruling. How our legal department allowed these unfounded, undocumented, unsubstantiated mutterings to be included in a legal document is cause for introspection.

Recently, at a location near Red Lodge, MT, Chairman Kavulla lambasted Southern Montana Electric (SME) for purchasing power then, because of an over-generation event, selling it at a loss and passing the stranded costs on to consumers. This was witnessed by several utility personnel present (perhaps the reason for this request) and reported in the press. Now he argues that proper policy is that planned over-generation with resulting below cost sales should be a stranded cost borne by NWE customers.

Such hypocrisy spouted by the Chairman generates the perception of regulatory uncertainty and predictably higher costs (rather than lowest costs possible) for regulated utility and co-op customers alike regardless of his forum.

CONCLUSION

NWE has specific authority to contract for QF power with curtailment language especially during light load hours. And they have federal and state statutory mandates to curtail on an economic basis to maintain consumer indifference. This was an unnecessary but interesting exercise that perhaps had more to do with Spion Kop than Two Dot.

I am perplexed as to why the Montana Consumer Counsel opted to be silent on this issue. Perhaps they have given up on the Montana Commission and are picking their battles. Perhaps they should intervene and ask for reconsideration and possible judicial review. Perhaps.

Over the last several decades too many Montana Commissioners have seen themselves as political engineers or environmentalists with an agenda dedicated to servicing the desires of QF developers rather than to consumer indifference and have, or rather continue to cost consumers literally hundreds of millions of dollars and put a strain on our economy. The findings of Order 7172 are a continuation of that sad heritage. There is no interpretation of any ARM or any MCA cite, made by myself, NWE, or any intervenor, that allows the purposeful over generation of electricity for the purpose of below costs sales from any type of generation.

While the Commission may have, correctly or incorrectly, discouraged certain specific curtailment language for future QF contracts NWE still has a legal obligation to implement curtailment to insure consumer indifference and statutory compliance. Hopefully a more populist future Commission shall hold them to it or, if the courts have not acted, help them implement it.

Brad Molnar

BRAD MOLNAR, Commissioner
MT PSC District II

Service Date: September 13, 2011

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

IN THE MATTER OF the Petition of NorthWestern Energy for a Declaratory Ruling on the Applicability of 18 C.F.R. 292.304 (f) and ARM 38.5.1903 (1) to Contracts with Qualifying Facilities	)))))	REGULATORY DIVISION DOCKET NO. D2011.7.57 ORDER NO. 7172

CONCURRING OPINION OF
COMMISSIONER TRAVIS KAVULLA

The current Qualifying Facility regime is by no means desirable. When NorthWestern Energy Corp. ("NorthWestern" or "applicant" or "petitioner") files its resource procurement plan, it sets in motion another docket whereby the Commission pursuant to PURPA and Montana law plays market maker and sets out to do the impossible: creating a durable rate which reflects the "avoided cost" of energy over a short and long term. As the last few years make clear, however, there is nothing consistent or durable about the wider economy to whose vicissitudes the energy market is subject. A meaningful avoided cost is difficult to concoct if it is only being revised biennially or at an even longer interval. Similarly, it is difficult to ignore the fact that this Commission's rules have created a mode of political economy where nearly all QFs are built to a scale (10 aMW) which is decreed as an upper limit to a QF standard-offer contract by the Commission's administrative rules. Perhaps the eventual answer lies in taking this Commission out of the market-making game and leaving that role to the market itself via processes which do not revolve around fixed and inflexible prices like requests for proposals. None of the foregoing is directly at issue in this docket, but is so inexorably linked to any matter touching upon QF policy that it deserves enunciation as a preface.

At issue here is the applicant's attempt to use what is essentially a dead letter of the Commission's administrative rules, explicitly intended for a utility which owns a considerable amount of base-load generation, to introduce an utterly novel concept into the realm of PURPA-based regulation as it exists in Montana: one which is neither countenanced by the clear language of the governing tariff, which states that a QF shall be paid for "all hours" of generation, nor by a considered reading of the rule itself, nor, more quaintly, by a rudimentary sense of fair play and nondiscriminatory access which animates Montana's implementation of PURPA.

While sensitive to the outcomes wrought upon the system by an antiquated regime of QF regulation—which, inopportunely, NorthWestern seeks to exploit in this petition, rather than alter in a rulemaking—the Commission should try to enforce the letter and spirit of the law to the best of its ability. This includes an attempt to maintain impartiality between the assets NorthWestern owns or intends to own, and of those with whom it is entering into agreements. That guideline, and not an unremitting embrace of the status quo, is the spirit in which this Order, I hope, will be read.

The Dissent to this Order requires a few points of correction.[1] First, it confuses what is permitted under state and federal rules' existing curtailment language by conflating "operational conditions"—when curtailment is explicitly contemplated—with "market conditions." One is not the other. Market conditions, by which I mean a more expansive notion than the truncated view of spot prices the Dissent brooks, are anticipated by the avoided-cost tariffs. This Commission's tariffs put forth a multifaceted calculation of avoided cost resulting in three options. One option is premised upon a price available at market, another upon the acquisition of a long-term base-load asset (pegged, in the last tariff, to Colstrip IV, an avoided cost essentially established when the Commission, including the dissenter, voted to allow the utility's acquisition of it), and the third is based upon the cost of a long-term wind asset whose acquisition to comply with public policy is anticipated by the procurement plan. The asset being avoided, in other words, is different in term or fuelstock or uncertain other costs like wind integration in each of the three options, and therefore results in different avoided-cost rates. The Dissent should, but does not, ask itself: Could the prevailing low market prices be secured over a 25-year period? Obviously not.

The Dissent is accordingly confused about what is meant by "consumer indifference." The consumer is indifferent to whether the utility pays a spot price to a QF generator equal to what it

[1]Indeed, the Dissent requires more than a few points of correction. But in the interest of brevity, this Concurring Opinion, because the Dissent is unintelligible in parts, will not attempt to impute a meaning to its language.

would pay at the spot market. But the consumer also is indifferent whether NorthWestern buys from a coal-fired plant in which the utility owns a stake versus purchasing from a different generator—if the price paid on- and off-peak is the same. So, too, does the consumer not care whether NorthWestern complies with a public-policy requirement by obtaining its own wind asset, signing a non-QF power-purchase agreement with a wind company, or signing to buy with a small QF. The avoided cost and terms and conditions of a QF contract should, then, reflect as much as possible those which prevail with respect to non-QF generators or purchases: that is the concept of indifference which appears to elude the Dissent.

There are numerous other errors in the Dissent. It miscomprehends the nature of this year's overgeneration event and what it does and does not mean for the state's wholesale co-ops and utilities. It implies that a declaratory judgment's issuance in the absence of a public hearing is somehow improper. It pretends that the Order's "legal conclusions" are premised on a QF's concern over obtaining financing, when that point was merely reiterated within the Order, not advocated by it, as a comment the Commission had received (Order, p.5). Insidiously, even while inveighing against the "regulatory uncertainty" to which the Order will supposedly contribute, the Dissent appears to encourage NorthWestern to violate the same Order.

At its core, the Dissent is schizophrenic. While calling for a less activist Commission—a notion with which I am sympathetic—it forwards a vision of PURPA which goes far beyond the scope of the petition and itself engages in a dismal activism which is totally at odds with the clear meaning of the law and with the reality of electrical markets. Even while branding itself "populist," ironically the only thing the Dissent would accomplish is to encourage monopolism and set up a parallel set of rules which binds some but not others.

I CONCUR with the Order.

Travis Kavulla, Commissioner

Service Date: October 14, 2011

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

* * * * *

IN THE MATTER OF the Petition of NorthWestern Energy for a Declaratory Ruling on the Applicability of 18 C.F. R. § 292.304(f) and ARM § 38.5.1903(1) to Contracts with Qualifying Facilities	)))))	REGULATORY DIVISION DOCKET NO. D2011.7.57 ORDER NO. 7172a

ORDER ON RECONSIDERATION

1. The Montana Public Service Commission (MPSC or Commission) on September 13, 2011, issued Order 7172 (Order) rejecting the proposed contract curtailment language of NorthWestern Energy (NorthWestern or NWE) and holding that the proposed language was inconsistent with the rules of this Commission and the Federal Energy Regulatory Commision (FERC) regarding qualifying facilities (QFs). Order, p. 8. On October 7, 2011, NWE filed a Motion for Reconsideration (Motion).

2. MPSC denies the Motion for the reasons outlined below.

Background

3. The proposed NWE contract language is described in the NWE Petition, which was filed on July 8, 2011. Order, pp. 2-3. That language is further explained in Exhibit C to NWE's proposed QF contract. Although NWE did not supply the Commission with that Exhibit, it was contained in the August 1, 2011, Comments of Hydrodynamics.

4. The Motion asks that the Commission address four issues on reconsideration, and that it "identify each perceived shortcoming in NorthWestern's curtailment proposal, along with

the specific legal basis for those conclusions, such that NorthWestern can move forward on a fully-informed basis." Motion, p. 12.

Issue 1 "[T] he Order's broad, sweeping rejection of NorthWestern's curtailment provision directly conflicts with a core requirement of PURPA—that a utility need not purchase power from a QF when negative avoided costs would result..."

5. The Order at pages 7 and 8 compared NWE's proposed language to FERC and MPSC rules and FERC discussion in the rulemaking process, emphasizing the limitation to curtailment in which "operational circumstances" require cut backs of base-load generation "followed by an immediate need to utilize less efficient generating capacity to meet a sudden high peak." ARM Sec. 38.5.1903 (1), as quoted at Order 7172, p. 7. While already quoted at p. 7 of the Order, that language apparently bears repeating. The rule provides that a utility is relieved of its obligation to purchase QF output

> (iii) if, due to operational circumstances, purchases from a qualifying facility will result in costs greater than those which the utility would incur if it did not make such purchases. This provision is only applicable in the case of light loading periods in which the utility must cut back base load generation in order to purchase the qualifying facilities production followed by an immediate need to utilize less efficient generating capacity to meet a sudden high peak.

6. NWE's proposed language is inconsistent with and far exceeds the scope of this rule. NWE's contract language, including Exhibit C, describes a planning activity that the utility will conduct to determine whether a surplus exists. Total load is compared to total resources. If a surplus exists in light load periods, the utility reserves the right to declare a surplus and allocate curtailments in any manner it determines appropriate. By contrast, an operational circumstance (as contemplated by the rule) would most likely be a plant-related occurrence.

7. NWE stresses a general formulation by FERC of its desire to avoid negative avoided costs (and resulting payments by QFs to the utility) from the FERC rulemaking Order (Motion, p. 5), but ignores FERC's rule that acknowleges that long-term avoided costs will at times exceed prices from the market or contracts of different terms. 18 CFR Sec. 292.304 (a)(5).

Issue 2 "[T]here is some indication that the Order is based on a legal conclusion that PURPA restricts the definition of baseload resources to physical assets that are owned by NorthWestern—to the exclusion of long-term PPAs."

8. NWE believes that the Order suggested that QF curtailment rules only apply if base load resources are owned by the utility. To the extent there is an ambiguity, the MPSC notes its view that, under the current rules, curtailment may legitimately be triggered when the utility's resources consist of a mix of owned and purchased resources.

9. Whether baseload resources are owned or purchased, this Commission's rule provides that necessary preconditions would still apply. In the case of a purchase agreement, necessary preconditions would include a "take or pay" provision, high start-up costs, and a lag in re-start times. Then other peak-load contracts would have to be relied upon in the interim while the base-load contracts were curtailed or "cut back" from generation, awaiting start-up. If such a situation does exist, necessitating the curtailment which NWE is arguing for, then NWE should make the Commission aware of it. The rule, however, does not contemplate curtailment due to excess purchases or for the sake of achieving a lower total cost from the resource stack resulting from market conditions, as discussed in response to Issue 1.

Issue 3 "[To] the extent the Order may reflect commenters' allegations that NorthWestern's proposal seeks 'excessive discretion'...or 'unbridled authority'..., the Order is based on groundless criticism."

10. NWE is encouraged to review its proposed curtailment provision, which contains the following language:

> During periods in which NorthWestern is purchasing energy both from Seller and Similarly-Situated Sellers, the implementation of any curtailments of delivery of energy is subject of the sole discretion of NorthWestern...

The provision continues by alluding to the language of Exhibit C to the contract. Exhibit C provides that:

> A determination of the amount of scheduled energy purchases to be curtailed and the Sellers to whom the curtailment procedures will apply is subject to the sole discretion of NorthWestern....

The broad scope of discretion NWE attempts to reserve to itself (as well as the potential for disparate treatment of QFs) speaks for itself, and could result in discrimination among QFs that is inconsistent with federal and state rules.

Issue 4 "[T]he Order incorrectly concludes that NorthWestern's Schedule No. QF-1 somehow overrides the curtailment regulations of both FERC and this Commission."

11. The MPSC agrees that the QF-1 tariff is not controlling; however, it suggests that NWE should modify it tariff to eliminate any inconsistencies.

Conclusion

12. The curtailment provision that NWE asks the Commission to authorize is at odds with the utility's own practice in light of some very recent history. NWE did not insist on curtailment language in the first three wind QF contracts which it signed in the past twelve months (Musselshell 1 and 2 and Gordon Butte). Nor did NWE insist on inclusion of curtailment language in its Power Purchase Agreement with Compass Wind. Docket No. 2011.5.41. This contract also provided the price point (i.e., the proposed avoided cost) which the utility asked this Commission to use as the premise for rates offered to QF wind projects. Docket No. D2010.7.77. Then, in July of this year, QF curtailment was advanced with rhetorical urgency with the filing of this proceeding and in NWE's most recent Motion. Whatever NWE's motives, its actions are inconsistent with its rhetoric. For this Commission to approve this about-face in policy would be inconsistent with the regulatory objective of providing consistent treatment to entities that are similarly-situated.

13. In other decisions contemporaneous with this Order, the MPSC is attempting to rectify problems that it perceives in QF policy.

ORDER

NOW THEREFORE IT IS ORDERED:

That the Motion for Reconsideration of NWE is denied.

DONE AND DATED this 13th day or October 2011 by a vote of 3 to 2. Commissioner Molnar and Gallagher dissenting.

BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION

TRAVIS KAVULLA, Chairman

GAIL GUTSCHE, Vice Chair

W.A. GALLAGHER, Commissioner (Dissenting)

BRAD MOLNAR, Commissioner (Dissenting)

JOHN VINCENT, Commissioner

ATTEST:

Aleisha Solem
Commission Secretary

(SEAL)

REQUEST FOR PRODUCTION NO. 2: Please provide copies of all documents related to Idaho Power's acquisition of RECs from existing or proposed QF PRUPA [sic] projects.

RESPONSE TO REQUEST FOR PRODUCTION NO. 2: Idaho Power objects to this Request on the grounds of relevance. The Direct Testimony of Lisa A. Grow submitted in this proceeding specifically states, ". . . the Company has no specific request of the Commission in this regard [i.e., related to RECs] at this time." Grow Testimony at p. 14, ll. 6-8. Since Idaho Power has no specific request regarding RECs in this proceeding at this time, questions related to RECs are irrelevant and beyond the scope of this docket.

Idaho Power further objects to this Request as it is overly broad and would be unduly burdensome for the Company to provide the information requested.

In addition, some of the requested material is or may be privileged and protected by the attorney-client privilege as well as the attorney-work product doctrine.

Idaho Power does not specifically seek to acquire RECs from existing or proposed qualifying facility ("QF") Public Utility Regulatory Policies Act of 1978 ("PURPA") projects. Idaho Power includes the environmental attribute language below in initial Idaho draft PURPA agreements supplied to proposed PURPA projects.

> Under this Agreement, ownership of Green Tags and Renewable Energy Certificate (RECs), or the equivalent environmental attributes, directly associated with the production of energy from the Seller's Facility sold to Idaho Power will be governed by any and all applicable Federal or State laws and/or any regulatory body or agency deemed to have authority to regulate these Environmental Attributes or to implement Federal and/or State laws regarding the same.

During the process of negotiating the draft PURPA agreements into final form, Idaho Power and some counterparties have negotiated modifications to the above language that has resulted in either (1) Idaho Power owning 50 percent of the environmental attributes created by the project for the entire term of the Firm Energy Sales Agreement ("FESA") or (2) the project retaining ownership of the environmental attributes for the first half of the FESA term with Idaho Power retaining ownership of the environmental attributes for the last half of the FESA term.

Listed below are the PURPA projects from which Idaho Power has environmental attribute ownership rights.

Project Name	Environmental Attribute Ownership Description	IPUC Case number	Idaho Public Utilities Commission Order Number Approving the FESA
Fargo Drop Hydroelectric	50%*	IPC-E-11-27	32451
Dynamis Ada County Landfill Project	50%	IPC-E-11-25	Pending Approval
High Mesa Wind Project	10/10**	IPC-E-11-26	Pending Approval
Murphy Flats Solar Power Project	50%	IPC-E-11-10	32384
Clark Canyon Hydroelectric	10/10	IPC-E-11-09	32294
Rockland Wind Farm	10/15***	IPC-E-10-24	32125

*50% Project and Idaho Power each own 50 percent of the environmental attributes for the full term of FESA.

**10/10 Project owns environmental attributes during first the 10 years of the 20-year FESA; Idaho Power owns environmental attributes for the second 10 years.

***10/15 Project owns environmental attributes through the end of calendar year 2021. Idaho Power then owns the environmental attributes with the beginning of calendar year 2022 through the term of FESA (a minimum of 15 years as this is a 25-year agreement).

The response to this Request was prepared by Randy C. Allphin, Senior Energy Contract Coordinator, Idaho Power Company, in consultation with Donovan E. Walker, Lead Counsel, Idaho Power Company.

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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 METHODOLOGIES FOR CALCULATING PUBLISHED AVOIDED COST RATES.	)	CASE NO. GNR-E-11-03

CLEARWATER PAPER CORPORATION
J.R. SIMPLOT COMPANY
EXERGY DEVELOPMENT GROUP OF IDAHO, LLC

REBUTTAL TESTIMONY OF DR. DON READING

June 29, 2012

INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Don Reading and my business address is 6070 Hill Road, Boise, Idaho.

Q. ARE YOU THE SAME DON READING THAT FILED DIRECT TESTIMONY IN THIS CASE ON MAY 4, 2012?

A. Yes I am.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I will be rebutting certain aspects of the direct testimony of Commission Staff witnesses Mr. Rick Sterling and Dr. Cathleen McHugh. Specifically, I will discuss Mr. Sterling's positions on REC ownership, the use of a SCCT for determining capacity costs, Idaho Power's Schedule 74, fuel cost risk, and contract length; and Dr. McHugh's position on the first deficit year approach in the calculation of avoided cost rates offered to PURPA projects. There are numerous other positions they take in their testimony that I have already countered in my direct testimony. Therefore, although I continue to oppose those positions, I will not again challenge them here.

Q. WHAT COMMENTS DO YOU HAVE ABOUT MR. STERLING'S RECOMMENDATIONS ON THE OWNERSHIP OF RENEWABLE ENERGY CREDITS ("RECS") CREATED BY QF GENERATION?

A. Mr. Sterling states that he believes the issue of REC ownership should be resolved in this case, agreeing with Rocky Mountain Power and opposing Avista's recommendation that the ownership of RECs should be decided in a separate case (Idaho Power was silent on the issue).

Mr. Sterling presents a review of the arguments over who should own the RECs[1] and acknowledges,

> "All of the arguments . . . . have merit and may be persuasive in justifying REC ownership be (sic) either the utility or the QF."[2]

However, he decides that REC ownership should be granted to the purchasing utilities.[3] He supports this decision with several assertions.

Q. COULD YOU PLEASE OUTLINE MR. STERLING'S ARGUMENTS AND COMMENT ON THE LOGIC OF THOSE ARGUMENTS?

A. Yes. In concluding that purchasing utilities should be granted REC ownership, he argues:

> "[i]f Idaho was in a position where additional incentive was needed in order to stimulate further development of renewables or achieve an RPS standard, then it might be reasonable to assign ownership of RECs to QF project owners so that they would have an additional revenue stream that could enhance project economics. However, as recent history demonstrates, Idaho is not in a situation where renewables development is stalled or needs to be accelerated."[4]

Mr. Sterling's argument is thus, most simply, that *recent history demonstrates* renewable development is neither *stalled* nor *in need of acceleration,* and therefore PURPA projects do not need the benefit of REC ownership. However, this is a rearview mirror look at the QF industry in Idaho, and it belies the thrust of his testimony and the proposals of the utilities going forward.

The positions taken by Mr. Sterling and the utilities in this case will certainly produce unfavorable rates for REC-producing wind and solar projects. Mr. Sterling recommends

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[1] Direct Testimony of Rick Sterling, Idaho Commission Staff, pp. 39-42, GNR-E-11-03.
[2] *Ibid.*, p. 42.
[3] *Ibid.*
[4] *Ibid.*

abandoning the SAR method for the calculation of avoided cost rates for wind and solar projects larger than 100 kW, "... admittedly mostly due to its ability to produce favorable rates" under PURPA contracts.[5] There is no rational basis for Mr. Sterling's recommendation to award RECs to the purchasing utility rather than the QF. As I stated in my direct testimony, if the Commission were to accept the proposal advocated by the utilities and supported by Mr. Sterling, the result would be "PURPA-killing."[6]

Q. DOES MR. STERLING PRESENT OTHER ARGUMENTS IN SUPPORT OF HIS RECOMMENDATIONS REGARDING REC OWNERSHIP?

A. Yes. He concludes that utility ownership of RECs is consistent with the IRP method of calculating avoided cost rates. He states,

> Q. Aside from the need for the Commission, the Legislature, or the courts to determine REC ownership, are there pricing issues associated with RECs that need to be considered in setting avoided cost rates?
> A. Yes, there are. For example, under the IRP methodology, a utility's 20-year portfolio of new resources is modeled in computing avoided cost rates. Each utility's 20-year resource portfolio contains some renewable plants because they either represent the lowest cost resources or because they help satisfy expected RPS requirements or both. The utility would possess the RECs associated with resources contained in its preferred portfolio, and presumably any price premium associated with those RECs would be included in the cost of the projects. Consequently, the cost of RECs would, already be accounted for in computing avoided cost rates using the IRP methodology. Therefore, a utility paying the computed avoided cost to a QF under the IRP methodology should be entitled to ownership of the RECs.[7]

There are two significant problems with Mr. Sterling's testimony.

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[5] *Ibid.*, p. 6.
[6] Direct Testimony of Don Reading, Joint Parties, p. 69, GNR-E-11-03.
[7] Direct Testimony of Rick Sterling, Idaho Commission Staff, p. 46, GNR-E-11-03 (underscoring added).

Q. WHAT ARE THOSE PROBLEMS?

A. I underscored the first problem in the quote above where Mr. Sterling mentions the need for the Commission, the Legislature, or the courts to "determine REC ownership." This "need" cannot be dismissed as a mere aside. It is a fundamental determination that must be addressed before the Commission can proceed into the REC morass. Ms. Grow, Idaho Power's Vice President of Power Supply, prefiled testimony on this issue stating:

> "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."[8]

It appears from Ms. Grow's prefiled direct testimony that Idaho Power believes the question should be answered by the Legislature, as suggested by Mr. Sterling. Thus, it appears as though both Mr. Sterling and Ms. Grow concur that the Legislature may be the proper place to answer this most fundamental of questions.

Q. DO YOU KNOW IF THE IDAHO LEGISLATURE HAS ADDRESSED THIS QUESTION?

A. I know that the Idaho Legislature had a bill before it in the last session that addressed this issue and that Idaho Power, Avista and Rocky Mountain Power were listed as the primary contacts for that legislation. Attached as Exhibit 507 is a copy of the Statement of Purpose and Senate Bill 1364 entitled:

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[8] Direct Testimony of Lisa Grow, Idaho Power, p. 14, GNR-E-11-03.

RELATING TO THE PUBLIC UTILITIES COMMISSION; AMENDING CHAPTER 5, TITLE 61, IDAHO CODE, BY THE ADDITION OF A NEW SECTION 61-542, IDAHO CODE, TO DEFINE THE AUTHORITY OF THE PUBLIC UTILITIES COMMISSION AND ITS JURISDICTION OVER THE ENVIRONMENTAL ATTRIBUTES OF PUBLIC UTILITY REGULATORY POLICIES ACT QUALIFYING FACILITIES AND TO PROVIDE FOR USE AND IMPLEMENTATION OF ENVIRONMENTAL ATTRIBUTES; AND DECLARING AN EMERGENCY.

So, apparently Ms. Grow was correct that the Idaho Legislature was going to address the ownership of RECs. The bill was referred to a Senate Committee and no action was apparently taken on it as shown on attached Exhibit 508, the "Final Bill Status" report of the 2012 Idaho Legislature.

Q. WHAT DO YOU MAKE OF THE FACT THAT IDAHO POWER DECLINED TO ADDRESS REC OWNERSHIP BECAUSE IT THOUGHT THE LEGISLATURE WAS GOING TO DO SO, COUPLED WITH THE FACT THAT THE STAFF BELIEVES THAT THE LEGISLATURE MAY BE THE BEST PLACE TO ADDRESS REC OWNERSHIP?

A. Well, it is all quite confusing. I am sure Idaho Power would have liked the Legislature to pass its REC bill – but it didn't. I can also see why it would have preferred the Legislature to address the question given the PUC Staff's prior, very strong comments that RECs belong to the developers.

Q. THE PUC STAFF HAS PREVIOUSLY TAKEN THE POSITION THAT RECs BELONG TO THE DEVELOPERS?

A. Yes, and on more than one occasion. The Staff has filed unequivocal comments with the Commission arguing that RECs belong to the developers of QF projects. In IPC-E-04-02 Idaho Power had asked the Commission to grant it a right of first refusal to RECs in the PURPA QF context. In response the PUC Staff filed comments that provided:

> Staff recommends that the Commission issue a declaratory order stating that mandatory purchases from QFs under PURPA do not convey ownership of any marketable environmental attributes. Accordingly, any environmental attributes associated remain with the QF. Staff further recommends that the Commission deny the Company's proposal to require that QF developers from whom Idaho Power purchases energy grant Idaho Power a 'right of first refusal' to purchase the environmental attributes associated with the QF facility.[9]

The rationale was based on a legal argument that I am not prepared to address; suffice it to say that the Staff was concerned about something in the U.S. Constitution regarding taking people's property without compensation. In IPC-E-04-16 Staff filed comments in response to Idaho Power's request for a Commission order exonerating them from any ratemaking penalty for its waiver of environmental attributes in a PURPA contract. Once again, the Staff filed comments that strongly and unequivocally asserted that environmental attributes belong to the developer:

> Staff incorporates its related comments filed in Case No. IPC-E-04-02 as if expressly set forth herein and includes same as attachment to these comments. In those attached comments, Staff stated its belief that neither PURPA nor <u>Title 61 of the Idaho Code</u> gives the Commission jurisdiction over environmental attributes. Staff recommended that if the Commission determined that it has jurisdiction, that the Commission issue a declaratory order stating that mandatory purchases from QFs under PURPA do not convey ownership of any marketable environmental attributes. Accordingly, Staff recommended that any environmental attributes remain with the QF.[10]

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[9] Comments of the Commission Staff, Case No. IPC-E-04-02, p. 8.
[10] Staff Comments, Case No. IPC-E-04-16, August 13, 2004 at p. 4 (underscoring added).

I am not a lawyer, but I don't think it is a mere coincidence that the underscored portion of the above quote is the exact same Idaho Code Title that Idaho Power's proposed legislation was proposed to amend and to which Ms. Grow's testimony obviously referred.

Q. IT SEEMS SOMETHING MUST HAVE CHANGED TO HAVE STAFF NOW TAKING SUCH A DIFFERENT POSITION ON REC OWNERSHIP IN THE PURPA CONTEXT?

A. One would think so, but Staff's testimony suggests otherwise. Why else would they preface their REC ownership testimony with the identification of the "need for the Commission, the Legislature, or the courts to determine REC ownership?"

Q. YOU STATED YOU HAD TWO PROBLEMS WITH STAFF'S TESTIMONY NOTED ABOVE. YOU HAVE ADDRESSED THE FIRST, REC OWNERSHIP; WHAT IS THE SECOND ISSUE?

A. Staff's underlying reasoning, that IRP's value RECs, might have been valid if the value of any environmental attributes were in fact included in the computation of avoided costs. According Idaho Power's 2011 Integrated Resource Plan,

> The value of RECs is not included in the levelized cost estimates but is accounted for when analyzing the total cost of each resource portfolio. [11]

Therefore, the value of RECs is not part of the calculation of the levelized cost of the Company's generation plant. The value of RECs enters the portfolio analysis only after levelized costs are

[11] Idaho Power 2011 IRP, p. 72.

found. The IRP methodology that is proposed by Idaho Power, as well as the other utilities, to find avoided costs is focused on the determination of levelized costs and hence avoided cost calculations do not include compensation for the value of RECs. As I stated in my direct testimony, the avoided costs in Idaho compensate the QFs only for energy and capacity, and I continue to recommend the ownership of RECs remain with the QF.[12]

Q. MR. STERLING RECOMMENDS THE USE OF A PEAKER (SCCT) FOR THE CAPITAL COSTS RATHER THAN A BASE LOAD GAS-FIRED GENERATION UNIT. WHAT WAS HIS RATIONALE FOR THIS CHANGE?

A. Mr. Sterling concludes that an SCCT can be considered a capacity-only resource… He argues that because the SCCT is the least cost capacity-only resource, it better matches a QF's performance. According to Mr. Sterling, a QF cannot be counted on to provide power during the utilities' system peaks:

> SCCTs are generally added to utilities' resource portfolios to satisfy capacity-only needs, and are usually the least cost capacity resource available. Therefore, the cost of an SCCT can reasonably be considered a capacity-only cost. Utilities that add CCCTs to their portfolio do so because they have a need for both capacity and energy, thus the cost of a CCCT can be considered both a capacity and energy cost. CCCTs, because they are more efficient, generate energy at a lower variable cost than SCCTs, but the tradeoff is that they are more costly to construct.
>
> Under the methodology as proposed by the utilities, capacity and energy values are being calculated independently. Therefore, I maintain that the proper resource to use as the basis for computing capacity value is the lowest cost resource that could be added to provide capacity equivalent to what would

[12] Direct Testimony of Don Reading, Joint Parties, p. 59, GNR-E-11-03.

otherwise be provided by the QF. I believe that using a SCCT is probably most appropriate because it represents the lowest cost, nearly capacity-only resource.[13]

The optimal generation expansion path for a utility is to add a resource that meets the system needs at least cost. When the system requires smaller resource additions to meet growing demand, the optimal path is generally a peaking unit that has low capacity costs but at a trade-off of higher running costs. These peaking units would be added until they ceased to be the least cost resource, i.e. when their lower capacity and higher energy costs began to exceed the base load CCCT's higher capacity costs and lower running costs. Therefore, for a least cost growth path, a SCCT contributes more to the system than just capacity. As I stated in my direct testimony, all three of the utilities have either recently added or will soon add a CCCT to their resource stack.[14] Therefore, a CCCT is a more logical choice to use for the calculation of long-run avoided costs.

Q. DOES MR. STERLING SUPPORT IDAHO POWER'S PROPOSED SCHEDULE 74 THAT WOULD ALLOW THE UTILITY TO CURTAIL QFS FOR ECONOMIC REASONS?

A. Yes. His reasoning for support of Idaho Power's curtailment tariff is based on the same flawed logic presented by Idaho Power witness Tessia Park in her direct testimony. He also agrees with Idaho Power that the curtailment provisions apply not only to QF contracts going forward but also existing contracts.

Q. Idaho Power proposes that Schedule 74 apply to all QF facilities, both existing and new, that have Generator Output Limiting Controls (GOLCs) installed. Do

[13] Direct Testimony of Rick Sterling, Idaho Commission Staff, p. 17, GNR-E-11-03.
[14] Direct Testimony of Don Reading, Joint Parties, p. 9, GNR-E-11-03.

> you believe that, if approved, the Company would have the authority to apply the proposed tariff to existing facilities whose contracts were in place prior to the new tariff being adopted?
> A. Yes, I do. As explained by Idaho Power witness Tessia Park, FERC rules at 18 CFR 292.304(f) includes a provision that relieves utilities from an obligation to purchase during any period which, due to operational circumstances, purchases from QFs will result in costs greater than those which the utility would incur if it 13 did not make such purchases, but instead generated an equivalent amount of energy itself. Because this is a part of FERC rules, I think Idaho Power has always had that authority whether or not it is expressly spelled out in a contract or a tariff.[15]

Since I discussed the problems with Ms. Park's analysis that Mr. Sterling relied on in my direct testimony I will not repeat them here. However, Mr. Sterling does not factor into his reasoning the chilling effect such a provision would have on a QF's ability to gain financing. He also does not seem to see the potential legal problems that could arise through attempting to alter existing signed and Commission-approved contracts.

Q. COMMISSION STAFF PROPOSES THE MAXIMUM LENGTH OF A QF CONTRACT BE REDUCED FROM THE CURRENT 20 YEARS TO FIVE YEARS SUPPORTING IDAHO POWER'S PROPOSAL FOR PROJECTS USING THE IRP METHODOLOGY, WHILE SMALLER PROJECTS USING THE SAR METHODOLGOY WOULD REMAIN AT TWENTY-YEARS UNDER STAFF'S APPROACH. WHAT COMMENTS DO YOU HAVE ABOUT THE LOGIC OF MR. STERLINGS POSITION?

A. Mr. Sterling outlines the history of the Commission's decisions that have adjusted the

[15] Direct Testimony of Rick Sterling, Idaho Commission Staff, GNR-E-11-03, pp. 37 - 38.

contract length from its original 35 years down to 20 years, down again to five years, and then back up to 20 years. He contends that reducing the contract length to five years would not adversely impact QF development. As part of his justification he discusses QF development during the 68 month period when contract length was limited to five years.

> Q. During the approximately five and a half year period when contract length was limited to five years (September 1996 through May 2002), how many PURPA contracts were signed?
> A. There was only one PURPA contract signed in Idaho during this time frame. However, at the time, the eligibility cap for published rates was also limited to facilities one megawatt or smaller. In addition, published rates were also quite low, primarily due to low natural gas prices. Furthermore, most PURPA hydro and cogeneration projects had already been developed, while wind, solar and biogas technologies had yet to fully develop. The combination of all of these factors, not shortened contract length alone, caused very few PURPA projects to be developed in Idaho during this time period.[16]

He is correct that the 1 MW cap would impact the number and momentum of QF developments; however, currently gas prices are lower than they were during that period, and a major fact that wind, solar, and biogas were not being developed was due to the shorter contract length that prevents QFs from obtaining financing.

He dismisses the significant impact on financing of QF projects by limiting them to only a five year contract.

> Q. Do you believe that the Commission has a responsibility to ensure contract lengths are long enough to enable QFs to obtain financing?
> A. No, not necessarily. Long-term contracts have been used by the Commission in the past to boost development of PURPA projects. However, circumstances have changed. It would be contrary to the public interest to encourage PURPA

[16] Ibid., pgs 27, 28.

> development at a time when it is not needed to serve customers and at a time when poor economic conditions strain customers' ability to pay. I believe it would be good public policy for the Commission to use effective tools, such as limiting maximum contract length, to control the pace of PURPA development.[17]

Mr. Sterling apparently does not believe the Commission, under PURPA, has to provide contracts long enough that QFs can find financial backing. However, according to Idaho Power witness Mr. Hieronymus, one of the mandates of PURPA is to encourage cogeneration and small power production.

> Section 210 tasked FERC to devise rules that "it determines necessary to encourage cogeneration and small power production and to encourage geothermal facilities of not more than 80 megawatts capacity."[18]

As I stated in my direct testimony, "Limiting PURPA contract terms to five years would preclude the vast majority of QF developers from being able to secure financing for their projects" and thus would be discouraging rather than encouraging QF development.[19] Mr. Sterling also believes that shortening the contract length to five years would "control the pace" of PURPA activity in Idaho. As pointed out above and in my direct testimony, adopting Mr. Sterling's positions and the utilities' proposal in this case will essentially kill PURPA development. The loss of tax credits and renewable power incentives at both the state and federal level, in combination with current low gas prices, will already stop or at a minimum significantly slow QF development in Idaho. Imposing a set of policies aimed at stifling QF development , thus merely represents 'insult to injury" to the QF industry

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[17] Ibid., pgs 28, 29.
[18] Direct Testimony of William Hieronymus, Idaho Power Company, GNR-E-11-03, p. 18.
[19] Direct Testimony of Don Reading, Joint Parties, GNR-E-11-03, p. 46.

Q. ARE THERE ADDITIONAL REASONS COMMISSION STAFF GIVES IN SUPPORT OF REDUCING QF CONTRACT LENGTH TO FIVE YEARS?

A. Mr. Sterling contends that ratepayers' fuel cost risks are lower for a utility-owned resource than for PURPA projects.

> Fuel costs associated with utility-owned resources are also passed on to customers, partly through base rates and partly through PCAS. However, fuel costs are tracked annually and rates are adjusted accordingly. Consequently, while customers are exposed to fuel price risk for both PURPA and utility-owned resources, the annual adjustment of rates for Utility-owned resources exposes customers to less risk for utility-owned resources than for PURPA resources. Moreover, recovery of costs for utility-owned resources is not guaranteed. However, as previously stated, once a PURPA contract is approved by the Commission, customers are obligated to pay 100 percent of the costs.[20]

I am assuming when he says, "the annual adjustment of rates for Utility-owned resources exposes customers to less risk for utility-owned resources than for PURPA resources" he believes that the power supply costs that are passed on to customers annually will be lower than the those found in signed PURPA contracts. As I stated in my direct testimony, natural gas prices have been historically very volatile. When a utility's natural gas plant is approved and put into its rate base, its customers will annually be responsible for whatever the prices may be, whenever they may occur, over the life of the plant. Only if one assumes that natural gas prices will remain at their current low levels indefinitely into the future can you conclude that customers will pay less for generation from a utility gas resource than a PURPA project.

Mr. Sterling also states that the cost recovery for utility-owned resources is not

[20] Direct Testimony of Rick Sterling, Idaho Commission Staff, GNR-E-11-03, p. 31.

"guaranteed." In a strict theoretical sense, I would agree that regulation does not 'guarantee' recovery, but rather gives the utility the 'opportunity' to earn its approved rate of return. However, as a practical matter, the utilities usually do fully recoup their investment in a generation plant. For example, in the case of Idaho Power's Langley Gulch Plant, the Commission did essentially 'guarantee' the Company it would be able to recover its investment when it approved a certificate to build the plant. Even if, for example, the plant were to experience a temporary outage, the utility would continue to earn its '*un*guaranteed' rate of return on the temporarily out-of-service investment. In contrast, , a PURPA project is afforded no such benefit, and only earns revenue when it is able to deliver power; therefore, when unforeseen problems knock the QF offline, QF owners are not able to recoup their investments for lost generation.

Q. WHAT IS YOUR RESPONSE TO DR. MCHUGH'S OPINION ON THE FIRST YEAR DEFICIT APPROACH ADVOCATED BY THE UTILITIES?

A. Dr. McHugh is advocating for the Staff to reverse itself and reinstate the first year deficit approach in the calculation of avoided cost rates offered to PURPA projects. She reviews Staff's nine areas of concern when they recommended it be abandoned several years ago. She explains why some of the reasons are no longer valid and offers a new method of calculating the first year deficit based on both capacity and energy. She goes on to state the rationale for reinstating the first year deficit was 'sound':

Q. Why was the "first deficit year" concept abandoned?

A. At the time this was abandoned, Staff expressed concerns that determining the first deficit year was problematic *even though the underlying rationale for it was sound.*[21]

As I pointed out in my direct testimony, this means a utility acting prudently to meet its demand should always be in surplus; however, reducing avoided cost payments to PURPA projects for these surplus periods does not represent the proper calculation of the avoided cost for the utility in the long-term. I certainly disagree with her conclusion that the underlying reasoning for the first year deficit is sound. It is interesting that she agrees with and quotes Avista witness Mr. Kalich when on page 21, lines 5 through 9 of his direct testimony he states,

> *It is not fair to pay one resource with a low capacity factor and an equivalently high on-peak contribution the same per-MWh payment as second base load plant operating with a relatively high capacity factor all year round. Using the method, the low capacity factor resource would receive much lower total compensation even though the resource provided the same on-peak capacity benefit to the utility.*[22]

However as I pointed out in my direct testimony Mr. Kalich also says,

> It is often true that utilities are surplus in early years; being so is an essential part of providing reliable utility service. It also is true that QF developers would be affected by these surpluses were they to receive lower early-year payments during surplus years. But this effect is a reflection of true avoided costs.[23]

I strongly disagree that paying QFs lower early-year payments accurately reflects of "true avoided costs." It is not true that by implementing the first deficit year, and thereby denying QFs capacity

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[21] Direct Testimony of Cathleen MChugh, Idaho Commission Staff, GNR-E-11-03, p. 7. Emphasis in original.
[22] Ibid., pgs 10,11.
[23] Direct Testimony of Avista Witness Clint Kalich, GNR-E-11-03, pp.13-14.

payments in the early years, accurately reflects a utility's own generation plant. This is so because the utility receives full recovery of its capacity costs for the entire life of the plant – including the early years.

Q. DR. READING, DO YOU HAVE ANY CONCLUDING COMMENTS?

A. As I pointed out above there are numerous other positions taken by the Commission Staff in their testimony that I have already dealt with in my direct testimony that I continue to oppose. It is for the sake of brevity that they have not been addressed in the above rebuttal testimony. The Commission Staff in their direct testimony consider a wide range of issues dealing with the implementation of PURPA in Idaho and make recommendations on each aspect. It appears that if one were to put Staff's recommendations into two categories, one labeled pro-QF development and the other anti-QF development, virtually all would fall in the anti-QF development category. A plainly stated purpose of PURPA law is to 'encourage' independent power production. Taken together could lead one to conclude that Staff is strongly anti – if that is the case it is opposed to federal law and in my mind not in the public interest. If Staff's recommendations were adopted, as said in my direct testimony, it would be "PURPA-killing." It would be difficult for the industry to rebuild itself and contribute to electric system needs in any cost effective manner.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY ON JUNE 29, 2012?

A. Yes it does.

STATEMENT OF PURPOSE

RS21243C1

This legislation will require any benefits derived from RECs associated with the sale of renewable energy to investor owned utilities to flow to the benefit of the utilities' customers.

FISCAL NOTE

There is no impact to the General Fund.

Contact:
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LEGISLATURE OF THE STATE OF IDAHO

Sixty-first Legislature Second Regular Session - 2012

IN THE SENATE

SENATE BILL NO. 1364

BY STATE AFFAIRS COMMITTEE

AN ACT

RELATING TO THE PUBLIC UTILITIES COMMISSION; AMENDING CHAPTER 5, TITLE 61, IDAHO CODE, BY THE ADDITION OF A NEW SECTION 61-542, IDAHO CODE, TO DEFINE THE AUTHORITY OF THE PUBLIC UTILITIES COMMISSION AND ITS JURISDICTION OVER THE ENVIRONMENTAL ATTRIBUTES OF PUBLIC UTILITY REGULATORY POLICIES ACT QUALIFYING FACILITIES AND TO PROVIDE FOR USE AND IMPLEMENTATION OF ENVIRONMENTAL ATTRIBUTES; AND DECLARING AN EMERGENCY.

Be It Enacted by the Legislature of the State of Idaho:

SECTION 1. That Chapter 5, Title 61, Idaho Code, be, and the same is hereby amended by the addition thereto of a NEW SECTION, to be known and designated as Section 61-542, Idaho Code, and to read as follows:

61-542. ENVIRONMENTAL ATTRIBUTES OF PURPA QUALIFYING FACILITIES. (1) Definitions:

(a) "Environmental attributes" means any and all claims, credits, benefits, emissions reductions, offsets and allowances, howsoever entitled, resulting from the avoidance of the emission of any gas, chemical or other substance into the air, soil or water. Environmental attributes shall include, but are not limited to: (i) green tags, green and/or clean energy credits, renewable energy credits or renewable energy certificates; (ii) any avoided emissions of pollutants to the air, soil or water such as sulfur oxides, nitrogen oxides, carbon monoxide and other pollutants; (iii) any avoided emissions of carbon dioxide, methane and other greenhouse gases. Environmental attributes do not include: (i) tax credits or other tax incentives existing now or in the future associated with construction, ownership or operation of the qualifying facility; or (ii) adverse wildlife or environmental impacts.

(b) "PURPA" means the public utility regulatory policies act of 1978, 16 U.S.C. section 824a-3.

(c) "Qualifying facility" means a qualifying small power or cogeneration facility as defined in 18 CFR 292.101(b)(1) as that section may be amended or superseded.

(d) "Public utility" means an electrical corporation as defined in sections 61-119 and 61-129, Idaho Code.

(2) Ownership. The legislature hereby finds that, to the extent that environmental attributes are generated by or associated with qualifying facilities, such environmental attributes are attributes of the power purchased by the public utility from such qualifying facilities at avoided cost rates. All environmental attributes generated by or associated with such qualifying facilities shall be owned by the public utility purchaser of the power from the qualifying facilities, unless, with regard to any specific qualifying facility, such ownership is expressly assigned to the qualify-

Exhibit 507
GNR-E-11-03
D. Reading: Simplot,
Exergy, Clearwater
Page 2

ing facility by specific agreement with the public utility purchaser of the power, and such agreement is approved by the commission.

(3) Use. Environmental attributes owned by a public utility pursuant to this section may be used for any, or all, of the following purposes:

(a) Environmental attributes may be used by a public utility to satisfy the requirements of any state or federal renewable portfolio standards or requirements applicable to such public utility;

(b) Environmental attributes may be sold, and the proceeds of such sale utilized to offset, or partially offset, the power supply expense paid by customers of the public utility as determined by the commission;

(c) Environmental attributes may be assigned to a qualifying facility, as referenced in subsection (2) of this section, by specific agreement approved by the commission. Should the owner of a qualifying facility desire to enter into such specific agreement assigning ownership of the environmental attributes to the qualifying facility, the public utility owner of the environmental attributes shall negotiate in good faith with the owner of such qualifying facility.

(4) Implementation. The legislature hereby directs the commission to implement this requirement for all qualifying facility power purchase agreements entered into by public utilities subsequent to the date of enactment of this section.

SECTION 2. An emergency existing therefor, which emergency is hereby declared to exist, this act shall be in full force and effect on and after its passage and approval.

FINAL
BILL STATUS
2012

SECOND REGULAR SESSION
SIXTY-FIRST IDAHO LEGISLATURE

January 9, 2012 through March 29, 2012

CONTAINING COMPLETE COMPILATION OF ALL LEGISLATION INTRODUCED

Compiled by
Legislative Services
Research and Legislation
with the cooperation of
Office of the Secretary of the Senate
Office of the Chief Clerk of the House of Representatives

Rpt delivered to Governor on 03/29
04/05 Governor signed
Session Law Chapter 308
Effective: 07/01/12

S1364 ....by STATE AFFAIRS
PUBLIC UTILITIES COMMISSION - Adds to existing law to define the authority of the Public Utilities Commission and its jurisdiction over the Environmental Attributes of Public Utility Regulatory Policies Act qualifying facilities.

03/01 Senate intro - 1st rdg - to printing
03/02 Rpt prt - to St Aff

S1365 ....by STATE AFFAIRS
UNCLAIMED PROPERTY - Amends existing law to provide that personal information related to unclaimed property is exempt from disclosure; and to provide that the audit methodology of the unclaimed property program is exempt from disclosure under the Public Records Act.

03/01 Senate intro - 1st rdg - to printing
03/02 Rpt prt - to St Aff
03/05 Rpt out - rec d/p - to 2nd rdg
03/06 2nd rdg - to 3rd rdg
03/07 3rd rdg - **PASSED - 33-0-2**
AYES -- Andreason, Bair, Bilyeu, Bock, Brackett, Broadsword, Cameron, Corder, Darrington, Davis, Fulcher, Goedde, Hammond, Heider, Hill, Johnson, Keough, LeFavour, Lodge, McKague, Mortimer, Nuxoll, Pearce, Rice, Schmidt, Siddoway, Smyser, Stennett, Tippets, Toryanski, Vick, Werk, Winder
NAYS -- None
Absent and excused -- Malepeai, McKenzie
Floor Sponsor - Hill
Title apvd - to House
03/08 House intro - 1st rdg - to St Aff
03/21 Rpt out - rec d/p - to 2nd rdg
03/22 2nd rdg - to 3rd rdg
03/26 3rd rdg - **PASSED - 67-0-3**
AYES -- Anderson, Andrus, Barbieri, Barrett, Bateman, Batt, Bayer, Bedke, Bell, Bilbao, Black, Bolz, Boyle, Buckner-Webb, Burgoyne, Chadderdon, Chew, Collins, Crane, Cronin, DeMordaunt, Ellsworth, Eskridge, Gibbs, Guthrie, Hagedorn, Hart, Hartgen, Harwood, Henderson, Higgins, Jaquet, Killen, King, Lacey, Lake, Loertscher, Luker, Marriott, McMillan, Moyle, Nesset, Nielsen, Nonini, Palmer, Patrick, Pence, Perry, Raybould, Ringo, Roberts, Rusche, Schaefer, Shepherd, Shirley, Simpson, Smith(30), Smith(24), Stevenson, Thayn, Thompson, Trail, Vander Woude, Wills, Wood(27), Wood(35), Mr. Speaker
NAYS -- None
Absent and excused -- Block(Block), McGeachin, Sims
Floor Sponsor - Buckner-Webb
Title apvd - to Senate
03/27 To enrol
03/28 Rpt enrol - Pres signed
Sp signed
03/29 To Governor
Rpt delivered to Governor on 03/29
04/05 Governor signed
Session Law Chapter 309
Effective: 07/01/12

S1366 ....by STATE AFFAIRS
RULEMAKING - Amends existing law to provide statutory procedures for negotiated rulemaking and to provide for notices of rulemaking to be placed on an agency's website.

03/01 Senate intro - 1st rdg - to printing
03/02 Rpt prt - to St Aff
03/07 Rpt out - rec d/p - to 2nd rdg
03/08 2nd rdg - to 3rd rdg
03/13 3rd rdg - **PASSED - 34-0-1**
AYES -- Bair, Bilyeu, Bock, Brackett, Broadsword, Cameron, Corder, Darrington, Davis, Fulcher, Goedde, Hammond, Heider, Hill, Johnson, Keough, LeFavour, Lodge, Malepeai, McKague, McKenzie, Mortimer, Nuxoll, Pearce, Rice, Schmidt, Siddoway, Smyser, Stennett, Tippets, Toryanski, Vick, Werk, Winder
NAYS -- None
Absent and excused -- Andreason
Floor Sponsor - McKenzie
Title apvd - to House
03/14 House intro - 1st rdg - to St Aff
03/21 Rpt out - rec d/p - to 2nd rdg
03/22 2nd rdg - to 3rd rdg
03/26 3rd rdg - **PASSED - 67-0-3**
AYES -- Anderson, Andrus, Barbieri, Barrett, Bateman, Batt, Bayer, Bedke, Bell, Bilbao, Black, Bolz, Boyle, Buckner-Webb, Burgoyne, Chadderdon, Chew, Collins, Crane, Cronin, DeMordaunt, Ellsworth, Eskridge, Gibbs, Guthrie, Hagedorn, Hart, Hartgen, Harwood, Henderson, Higgins, Jaquet, Killen, King, Lacey, Lake, Loertscher, Luker, Marriott, McMillan, Moyle, Nesset, Nielsen, Nonini, Palmer, Patrick, Pence, Perry, Raybould, Ringo, Roberts, Rusche, Schaefer, Shepherd, Shirley, Simpson, Smith(30), Smith(24), Stevenson, Thayn, Thompson, Trail, Vander Woude, Wills, Wood(27), Wood(35), Mr. Speaker
NAYS -- None
Absent and excused -- Block(Block), McGeachin, Sims
Floor Sponsor - Moyle
Title apvd - to Senate
03/27 To enrol
03/28 Rpt enrol - Pres signed
Sp signed
03/29 To Governor
Rpt delivered to Governor on 03/29
04/05 Governor signed
Session Law Chapter 310
Effective: 04/05/12

S1367 ....by FINANCE
APPROPRIATION - GOVERNOR, EXECUTIVE OFFICE OF - Appropriates $1,910,200 to the Executive Office of the Governor for fiscal year 2013; limits the number of full-time equivalent positions to 26; exempts appropriation object and program transfer limitations; and provides guidance for employee compensation and benefits.

03/01 Senate intro - 1st rdg - to printing
03/02 Rpt prt - to Fin
03/05 Rpt out - rec d/p - to 2nd rdg
03/06 2nd rdg - to 3rd rdg
03/07 3rd rdg - **PASSED - 33-0-2**
AYES -- Andreason, Bair, Bilyeu, Bock, Brackett, Broadsword, Cameron, Corder, Darrington, Davis, Fulcher, Goedde, Hammond, Heider, Hill, Johnson, Keough, LeFavour, Lodge, McKague, Mortimer, Nuxoll, Pearce, Rice, Schmidt, Siddoway, Smyser, Stennett, Tippets, Toryanski, Vick, Werk, Winder
NAYS -- None
Absent and excused -- Malepeai, McKenzie
Floor Sponsor - Toryanski
Title apvd - to House
03/08 House intro - 1st rdg - to 2nd rdg
03/09 2nd rdg - to 3rd rdg
03/16 3rd rdg - **PASSED - 61-3-6**
AYES -- Anderson, Andrus, Bateman, Batt, Bayer, Bedke, Bell, Bilbao(Reynoldson), Black, Bolz, Boyle, Buckner-Webb, Chadderdon, Chew, Collins, Crane, Cronin, DeMordaunt, Ellsworth, Eskridge, Gibbs, Guthrie, Hagedorn, Hart, Hartgen, Harwood, Higgins, Jaquet, Killen, King, Lacey, Lake, Loertscher, Luker, Marriott, McGeachin, Moyle, Nesset, Nielsen, Nonini, Palmer, Patrick, Pence, Perry, Raybould, Ringo, Rusche, Shepherd, Shirley, Simpson, Sims, Smith(30), Smith(24), Stevenson, Thayn, Thompson, Trail, Vander Woude, Wills, Wood (27), Wood(35)
NAYS -- Barrett, McMillan(McMillan), Schaefer
Absent and excused -- Barbieri, Block(Block), Burgoyne, Henderson, Roberts, Mr. Speaker
Floor Sponsor - Thompson
Title apvd - to Senate
03/19 To enrol
Rpt enrol - Pres signed
03/20 Sp signed
03/21 To Governor
03/22 Rpt delivered to Governor on 03/21
03/26 Governor signed
Session Law Chapter 133
Effective: 07/01/12

S1368 ....by FINANCE
APPROPRIATION - LIEUTENANT GOVERNOR - Appropriates $142,800 to the Office of the Lieutenant Governor for fiscal year 2013; limits the number of full-time employees to 3; and provides guidance for employee compensation and benefits.

DON READING,

produced as a witness at the instance of the Clearwater Paper Corporation, et al, being first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. RICHARDSON:

Q. So are you the same Dr. Reading who was recently advised by your cardiac doctor to avoid stressful situations?

A. Yes.

MS. SASSER: I object.

COMMISSIONER SMITH: And I told him yesterday that it was his lawyer that was actually doing the most damage.

MR. RICHARDSON: Guilty as charged, Madam Chair.

Q. BY MR. RICHARDSON: Are you -- Dr. Reading, are you the same doctor --

First of all, state your name and your employer, please.

A. Don C. Reading, R-E-A-D-I-N-G. And what was the follow-up?

Q. Who are you employed by?

A. Ben Johnson Associates of Tallahassee, Florida.

Q. And are you the same Dr. Reading who caused prepared -- prefiled direct and rebuttal testimony to be filed in this case?

A. Yes.

Q. And did you prepare or did you supervise the preparation of Exhibits No. 501 through 507 (sic)?

A. Yes.

Q. And do you have any corrections or additions to make to your prefiled testimony or exhibits?

A. The one correction that I found was on page 44, line 9. I said Langley Gulch was 330 megawatts. I think that's an old number, and it's 300 megawatts. So that would be the only correction.

Q. With that correction, if I were to ask you the questions you were asked in your prefiled testimony today, would your answers be the same?

A. Yes, they would.

Q. Thank you, Dr. Reading.

MR. RICHARDSON: Madam Chair, I'll move that Dr. Reading's prefiled direct and rebuttal testimony be spread upon the record as if it were read in full.

COMMISSIONER SMITH: Seeing no objection, it is so ordered.

(The following prefiled direct and rebuttal testimony of Dr. Reading is spread upon the record.)

(The following proceedings were had in open hearing.)

MR. RICHARDSON: And I'll ask that Dr. Reading's Exhibits 501 through 507 (sic) be marked for identification purposes.

COMMISSIONER SMITH: Seeing no objection, the exhibits will be.

(Clearwater Paper Corporation, et al, Exhibit Nos. 501-508 were premarked for identification.)

MR. RICHARDSON: Thank you, Madam Chair. We have no preliminary matters. Dr. Reading is available for cross-examination.

COMMISSIONER SMITH: Thank you, Mr. Richardson.

Any questions, Mr. Miller? Mr. Uda? Mr. Williams. Mr. Arkoosh is gone.

Mr. Otto.

MR. OTTO: No questions, Madam Chair.

COMMISSIONER SMITH: Ms. Nelson.

MS. NELSON: No questions, Madam Chair.

COMMISSIONER SMITH: Mr. Solander.

MR. SOLANDER: Yes, please.

CROSS-EXAMINATION

BY MR. SOLANDER:

Q. Good afternoon, Dr. Reading.

A. Good afternoon.

Q. You state in your testimony on page 61 of your direct that you believe a QF contract and tariff would be useful?

A. You're referring to which line?

Q. It is line 4, beginning on line 4, on page 61.

A. Yes.

Q. And do you agree generally that aside from a few of the response periods that are included in Rocky Mountain Power's proposed Tariff 38 that you I believe said are too long, do you believe that it's a reasonable approach?

A. I believe the -- it is a reasonable approach to establish the -- you know, the conditions that the -- the philosophy of Schedule 38, I certainly agree with.

MR. SOLANDER: Thank you. I have no more questions for Dr. Reading.

COMMISSIONER SMITH: Ms. Sasser, do you have questions?

MS. SASSER: I do. Thank you, Madam Chair.

CROSS-EXAMINATION

BY MS. SASSER:

Q. Good afternoon, Dr. Reading.
A. Good afternoon.
Q. Nice to have you with us.
A. You don't know how nice it is to be with you.
Q. I'll be gentle.
A. Yes.
Q. You generally testify that $45 a kilowatt hour is excessive for liquidated damages. Is that correct?
A. I would have to review my testimony. I can't recall the $45 necessarily being excessive. I think it's arbitrary and unnecessary.
Q. Okay. Do you believe the 45 kW is excessive then?
A. The $45?
Q. $45 a kW.
A. Yes. Yeah, it -- my position is, when you read my testimony, is that it -- liquidated damages should be based on what damages actually could be or would be.
One of the things I find curious looking at the -- excuse me -- $45 liquidated damages is that all three Utilities have that and they have the same thing for all the different types of QFs, yet one of the major points of IRP

methodology, et cetera, is -- is that different types of QFs impose different types of costs on the Companies. So just to pluck $45 out and say that's it I think is not the proper approach.

Q. Okay. Isn't it true that if market prices far exceed avoided cost rates the way that they did in, say, early 2000, 2001, that actual damages for a Utility could far exceed the 45 kW?

A. Potentially, yes, but that would be decided once whatever breach is -- whatever the lawyers come to on whatever the breach is, and then determine what the actual property loss would be.

Q. Okay. So for my own clarification then, it is only your testimony that $45 kW is arbitrary, but not excessive necessarily?

A. Depends on the circumstances.

Q. Okay. Fair enough. What obligation does a QF facility have to perform if their liquidated damages happen to be zero?

A. They don't get any revenue and can't pay the bank back. They -- a QF only gets paid when they supply power to the Utility.

Q. Would it be fair to allow a Utility to delay a QF's online date without penalty if it were in the Utility's best interest?

A. You need to tell me more.
Q. What I'm getting to is if -- if the argument by the QF industry is that the Utility is not suffering any harm by them not coming online --
A. Okay.
Q. -- then does the Utility get that same argument against the QF?
A. I believe my position is not that the Utility is not having -- not experiencing any harm by a QF not coming on. My testimony says that those damages should be specific. And so I would, depending on the QF and what happened and what prices in the market is, et cetera, et cetera, and I would turn the coin over equally and say I don't think the Utilities would be shy at all about coming after their -- you know, what would be in their best interests. They have the same understanding, it's the same rules. It should be actual property damage after whatever the cause is.
Q. Okay. If you can turn to page 50 of your direct testimony, you --
Are you there? I'm sorry.
A. Yes, I am.
Q. Okay. You speak about the current wind integration charge and its consideration of curtailment circumstances being included in that charge. Is that correct?
A. Correct.

Q. Can you explain how the wind integration charge accounts for low load conditions here in Idaho?

A. The -- the theory behind what I have in that section of my testimony is that wind integration charges are charged because it's an intermittent resource. To me, that implies that the -- you know, whatever load conditions happen to be, that the 6.50 should, in part, account for that.

Q. If you turn a couple pages to page 52 and 53 of your direct testimony --

A. Yes.

Q. -- you continue to address the circumstances under which you believe that FERC would allow curtailment?

A. Okay.

Q. And you describe a scenario under which FERC Regulations would apply. I'm looking for the line.

You say if slow ramping base load units had to be backed down during light load periods and the only way for the Utility to meet its next peak is with more expensive peaking resources such as that of a less efficient gas peaking unit, you surmise that, and I quote, "This does not appear to apply to Idaho Power for several reasons." And that's your testimony?

A. Yes.

Q. So would you agree then that if this Commission finds that that scenario that you give does apply to Idaho

Power, that Schedule 74 and the FERC Regulations then are consistent?

A. Without -- you're making me tread lightly here. There have been I wouldn't say "numerous," but "various" Commissions through time have come to conclusions that, after they come to those conclusions, I still don't agree with. Okay.

And my -- my theory of this whole section is -- and I might throw in that I'm one of numerous nonlawyer witnesses opining on close to legal ground -- that what FERC says it's for -- operational problems, that, you know, system reliability, those kinds of issues -- is where it would apply, but it wouldn't apply for, you know, back on more familiar territory where I am, economic reasons.

Q. On page 66 of your direct testimony, beginning at line 6, you state --

A. I'm not quite there yet.

Q. Okay.

A. Yes.

Q. You state that under existing Idaho precedents, QFs are almost always responsible for the network transmission upgrades required to deliver their energy. Do you see that?

A. Yes.

Q. With the exception of the Cassia group, which I'm sure you're aware of details on, how many QF are you aware of that have been required to pay for transmission upgrades in Idaho?

A. I would have to go back and look. I did not have a list in front of me, but based on my experience over time listening to developers tell me what the situations were. I do not have a list.

Q. Okay. Are you aware then, of those that may have been required to pay, how many were subject to a 100 percent refund?

A. No.

Q. Last question: If you reference page 2 and 3 of your rebuttal testimony --

Tell me when you're there.

A. Yes.

Q. -- you state that Mr. Sterling's position on REC ownership is PURPA killing. Is that correct?

A. That is correct. That is one of the elements that I see in this case that Staff's position has taken which, as a whole, would be PURPA killing, if you --

Q. So do I read that incorrectly then?

A. No. I think it's -- it certainly could be the straw that breaks the camel's back. I guess that would be my best way to put it.

Q. Okay. Isn't it true that PURPA does not address RECs or RECs' ownership?

A. That is correct.

Q. Then prior to RECs coming into existence, were there viable QFs that built and produced and completed projects in a financially responsible and beneficial manner?

A. Without being too snide from the Utilities' perspective, but obscenely high prices so that may have been the reason.

Let me explain a little bit my position of RECs, again a lot of opining of nonlawyers on the legality and what FERC says and doesn't say.

My view on RECs from an economic perspective is they're a by-product. And what I mean by a by-product is -- is that an entity produces X to sell it in the market and sometimes there is a by-product as a result of that production. What -- put my professor hat on for a sec.

I did a water rights case for Jerome Cheese, asked the plant manager, you know, What's your economic, what's your business model?

And he said that Kraft will buy every pound of cheese we can produce, no problem with milk.

And I said, Oh, well, that's great, you're making a ton of money.

He said, No, we don't make money -- we make money, but our big profit is -- is the whey. And the whey has proteins and whatever it is they can put in feed.

So, to me, saying that the Utility gets the RECs because it buys the electricity would be equivalent to Kraft going to Jerome Cheese and saying, You have to give us this valuable by-product because we buy all the cheese.

That, from an economic perspective, it's clear to me that RECs are a by-product and therefore --

Q. But so as I understand your answer in your example, QFs are viable and make money just producing the energy, but the big money is in the RECs?

A. You're stretching the example. I was trying to explain --

Q. I'm sorry, that's what I heard.

A. Nice try, Ms. Sasser.

-- that it was an example of a by-product.

Q. But there were -- the question more precisely was: There were viable QFs built and completing contracts prior to the creation of renewable energy credits?

A. Yes. And some were profitable and some had troubles.

MS. SASSER: Okay. That's all I have, thank you.

COMMISSIONER SMITH: Thank you.

Mr. Andrea.

MR. ANDREA: Thank you, Madam Chair.

COMMISSIONER SMITH: You also need to get closer to your mic. Thank you.

CROSS-EXAMINATION

BY MR. ANDREA:

Q. Good afternoon, Dr. Reading.

A. Yes.

Q. I want to follow up, to start, on a couple of questions that Ms. Sasser asked. I just want to make sure I understand your testimony.

Did I understand you to say that damages should be decided at the time of the breach based on market prices for power and other factors? Is that correct?

A. I would think would be a significant element, but the damages, you know.

Q. Okay.

A. Your profession make their money going into the hearing rooms and determining a wider band of those kinds of things. So certainly the price of power would be one, but a breach potentially could cause other damages.

Q. Okay. Fair enough.

A. It's a position the Utilities have taken.

Q. Sure. And did I also understand you to say that depending on what the market price for power was at the time of the breach, a $45 per kW damage would not necessarily be excessive?

A. That's the answer I gave to Ms. Sasser.

Q. If a QF executes a power purchase agreement with a Utility, say, five years before its commercial online date and they don't make that commercial online date, at the time that the contract is entered is there any way to accurately predict what those market power prices will be five years down the road?

A. Not accurately. We all project it, I mean, it's what we do, but often incorrectly.

Q. In your experience working with QFs, has it been your experience that some, maybe not all, but some QFs do not have substantial balance sheets that could cover, say, $45 per kW damage?

A. Well, if you don't -- I would like to clarify the question. The question you're asking is -- is that some QFs don't have the financial wherewithal to be able to come up with that $45 a kW payment, originally, and one of the points I make in my testimony is --

Q. I'm sorry, Dr. Reading, that was not my question.

A. Okay.

Q. So let me restate and maybe I can make it a little more clear.

A. Certainly.

Q. Really my question was isn't it true that some QFs do not have the financial wherewithal to pay for damages at the time of breach. I'm not talking about whether they have the wherewithal to post the security; I'm ask asking whether they, in the absence of security, would have the financial wherewithal to pay those damages should they occur.

A. You mean, five years down the road, what's their financial condition?

Q. And in your experience, isn't it true that some QFs do not have a significant enough balance sheet to pay those damages?

A. Let me answer it this way: I cannot think of one specifically, but hypothetically and theoretically as an economist, I could certainly imagine that situation.

Q. Okay, thank you very much, Dr. Reading. I'll move on to a different subject. You've got your testimony up there with you. Correct?

A. Yes.

Q. Okay. I'd like to direct your attention to page 7 of your direct testimony. And let me know when you're there.

A. I am there.

Q. Okay. Starting on line 7, you state that the SAR methodology has been robust through all of those changes, and has produced avoided cost rates that have proven to be remarkably accurate in hindsight. Is that correct?

A. That is correct.

Q. And when you talk about "through all of those changes," you're really talking about changes over a three-decade time frame. Is that right?

A. Yeah, count. Thirty years. I guess we are. If not, it's close.

Q. I'm just looking at lines 3 and 4 on the same page.

A. Okay.

Q. It says Idaho's energy --

A. Okay, I say "three decades," yes.

Q. Three decades. When you say that the SAR has produced avoided cost rates that have proven to be remarkably accurate, what do you mean, remarkably accurate as to what?

A. As to mimicking what the long-run avoided cost of the Utility is based on the fact that that's what it would cost them to build their next resource.

Q. Okay. So in preparing this testimony, did you go back and review all of the published avoided cost rates over that 30-year period?

A. No, but I'm generally -- I was here, I was on the Commission Staff when PURPA started, so I'm generally familiar with the history of avoided cost rates.

Q. Okay. Did you perform any analysis to determine the accuracy of those rates as compared to a Utility's avoided cost, as you describe them?

A. No, I performed no analysis of that.

Q. So it's fair to say you base that statement on absolutely no data or analysis. Is that correct?

A. On 30 years' experience about playing in this sandbox, you know.

Q. Okay. Thank you, Dr. Reading.

Can we move to page 15 of your direct testimony. Let me know when you're there.

A. I am there.

Q. On page 15, just speaking generally, you take issue with what you state is Mr. Kalich's assumed definition of "true avoided cost." Is that fair to say?

A. Yes.

Q. What is your understanding of what true avoided cost means?

A. As I hoped to explain in my testimony, true avoided cost would be what it costs the Utility to provide power over a arbitrarily 20-year period. Otherwise, if a Utility is out building its own resources, be it a gas plant or a coal plant or a hydro dam or whatever, the avoided cost would then be what that next viable unit would be for that particular Utility.

Q. Okay. Is it your view that QFs should be compensated for, and that avoided cost rates should include compensation for, capacity that the QF's resources does not provide or for that the capacity that the Utility does not need?

A. Certainly, I can answer the second part: What kind of a QF would not provide capacity?

Q. Hypothetically, you could -- for example, a summer-peaking Utility, perhaps a canal drop, may not provide; or winter-peaking Utility, a canal drop may not provide capacity. There are resources that may fit that description.

A. And, theoretically, we would have to go into it.

I am not opposed to seasonality in rate structures. What I am opposed to is the theory that the sufficiency period or that there should be no capacity payment in the -- in -- during periods of surplus for a Utility. And I find it curious in this docket where folks are saying let's move the -- Mr. Kalich's statement that Utilities are often surplus in the short run.

My opinion is -- is that it's probably more than some of the time, it's probably most of the time.

And I would add that if a Utility is doing what it should be doing, it's always surplus in the short run because investment is lumpy. And I don't want to go into all kinds of a lecture here, but I think I quoted out of the Grey Book, et cetera, when you have lumpy investment that you're always going to have a surplus period, so that if you have a QF, it's never going to get that capacity payment. But that isn't the, in my mind, true avoided cost. True avoided cost is what it costs to build that next plant.

Q. Give me just a second, Dr. Reading. Thank you.

So, Dr. Reading, if a QF has the ability to come in and sign a contract as early as five years before their expected commercial operation date, doesn't that substantially eliminate the problem of Utilities being surplus in the short run and actually provide more of an opportunity for the QF to be compensated for its capacity earlier in the contract term?

A. I guess I don't track you. Your logic escapes me, so give it to me again. And I'm not saying it's you; I'm saying I didn't track the question.

Q. That's fair enough. Please always ask for clarification. I'll be happy to try.

If the QF comes in and signs a contract five years before its expected commercial operation date and that Utility begins to plan for that resource to be part of its system, doesn't that substantially mitigate the potential for QFs to not be cooperative, to be compensated for capacity at the beginning stages of the contract?

A. I would need to answer that by saying it depends on when the price is locked in. Because when the Utility offers a QF a avoided cost price, they calculate that -- at least what's being proposed in this docket -- they do that, they offer that price based on what they view at this particular time what their surplus would be. And in that case, the avoided cost would be significantly lower because you wouldn't be getting capacity payments for that surplus period.

Q. Okay. Thank you. And I just want to hopefully get a really quick, short answer on the first part, because you went to the second part of the question. And I apologize, I should have pulled them apart. And so let's go back to the first part of the question:

Is it your view that QFs should be compensated for attributes they do not provide to the Utility, such as capacity?

A. If they -- if it -- not necessarily.

Q. Okay. Thank you. Can we turn to page 19 of your testimony?

A. Yes.

Q. On page 19, starting on line 7, you state -- and I'm not quoting you, so tell me if I mischaracterize -- generally that you agree that the Commission should use the regularly updated gas forecasts generated by the EIA in its annual outlook report as the forecast for the Commission to use for updates of the published gas SAR avoided cost rates?

A. Correct.

Q. Is it important, in your mind, to regularly update gas prices using a good forecast for purposes of setting --

A. A what forecast?

Q. Is it important, in your mind, to regularly update gas prices using a good forecast for purposes of setting the avoided cost rates?

A. I'm missing it. A what forecast again?

COMMISSIONER SMITH: "Good."

THE WITNESS: What?

COMMISSIONER SMITH: "Good."

Q. BY MR. ANDREA: "Good."

A. Good. Oh. Only if you hire Ben Johnson Associates to do your forecasting.

Yes, I would say, given the definition of what "good" is. And I think for something like calculating avoided cost, an important -- two important elements is, one, that is from a third party that doesn't have a dog in the fight; and also that it is transparent where everybody can look at it.

Q. So gas forecasts are an important element for setting an accurate avoided cost rate?

A. Yes.

Q. Okay. Can I get you to turn to page 34 of your testimony?

A. I am there.

Q. Okay. Thank you. On page 34, you have a chart that purports to compare the costs of Langley Gulch compared to calculations of certain resources using the current and proposed IRP methodology. Is that correct?

A. That is correct.

Q. And correct me if I'm reading the chart incorrectly, but it said, as I read it, the chart shows a high of roughly $111 per megawatt for Langley and a low of roughly $47 for a 20 megawatt base load resource using the proposed IRP methodology. Is that correct?

A. Yes. And that's Idaho Power's, as I remember, numbers.

Q. Okay. The $111 number is -- for Langley is based on a calculation that was done in 2009. Is that correct?

A. Yes, when they came in.

Q. And the $47 number was calculated using the proposed IRP methodology, but was calculated this year. Is that correct?

A. About a year ago, yeah.

Q. Okay. So, in 2011?

A. Yep.

Q. In preparing this chart, you didn't make any adjustment for gas prices, did you?

A. No. I didn't have the ability. I tried to take some numbers and compare them, and I would have to have had all of the models up and running and put in whatever gas prices would be deemed appropriate, and I may well consider a different gas price appropriate to what the Utility used. I didn't know exactly what they used.

Q. But you made no adjustment?
A. I made no adjustment, no.
Q. Are you aware that gas prices have changed significantly since 2009?
A. We all are, yes.
Q. Okay. So comparing $111 for Langley Gulch 2009 prices to the $47 IRP methodology is really -- it's apples to oranges. Correct?
A. I would say maybe it's Granny Smiths to Romes. I don't think it's completely inaccurate.
And one thing in looking at this analysis, which would change at -- let's say for Langley Gulch, it's 65 percent capacity factor. A later filing by the Staff, as I remember, said Langley Gulch was only going to run at, like, 40 percent or something. So natural gas prices are a element in explaining the difference in prices, but if we're going to adjust that, I would have to have gone through and adjusted all other kinds of variables that may affect it both up and down.
Q. Okay, thank you. Just a couple more -- well, a couple more with several follow-ups, but I'll try and be as brief as possible.
On page 45 of your direct testimony -- can you go there.
A. Yes.
Q. On this page of your testimony, this part of your

testimony, you point to Avista's Reardan Wind Project as an example of a Utility plant taking longer than two years to achieve online status. Is that --

A. Yes.

Q. -- generally correct?

Are you aware that Avista has at least, for now, decided not to pursue Reardan?

A. Yes.

Q. So it really isn't fair, the statement, to say Reardan demonstrates it takes longer than two years for a project to come online, does it?

A. The point that I was attempting to make by using Reardan -- well, I guess there would be two elements to it:

There seems, in my mind, there seems to be a confusion on two years and then comparing it to how long it takes to construct it. If you're building a project, be it hydro or wind or anything, the whole process takes significantly longer than two years. For wind project, you have to put up a tower; for hydro project, you have to worry about environmental constraints. So I talk about the whole block of time.

And for Reardan, you said that, for now, that the Utility has decided not to build Reardan. And, I'm sorry, I've missed the other name because you purchased another --

Q. We'll talk about that in a minute. Let's just

focus on Reardan for a moment.
A. Okay. And as I understand the Commission's Order, you are not collecting from ratepayers but you are booking both CWIP and AFUDC so that -- and preserving the site, and so down the road if Avista decides to build it, then I assume that it would ask the Commission for reimbursement plus probably missed interest in the interim.
Q. So let's talk about Palouse Wind. You're aware of our Palouse Wind Project?
A. Just what I've read.
Q. But you're generally aware --
A. Yeah.
Q. -- that Avista has acquired through a PPA approximately 100 megawatt -- slightly higher than a 100-megawatt wind project?
A. Yes. And my understanding, it was a better deal than Reardan.
Q. Do you know how long that project is expected to take to develop?
A. No, I do not.
Q. Would it surprise you to know that Avista issued the RFP for that project in early 2011?
A. I will accept that.
Q. Would it surprise you to know that that project is expected to be in commercial operation by the end of this

year?

A. I will accept that.

Q. So in other words, you would accept that it could take less than two years to develop a 100-megawatt wind project?

A. Depending on the financing and where you are. You said it's a PPA. I don't know who the developer of the project is and how much front-end time it took them to determine that that was the best place to put it, get their interconnection agreements, those kinds of things.

I will accept that two hours from -- I mean, two years on the PPA. What I don't know is what all that front end was from the developer you're purchasing the PPA from.

Q. All right. Let's move on to page 31 of your direct testimony.

A. Yes.

Q. So on page 31 --

Are you there, sir?

A. Yes.

Q. -- starting on line 17, you state: Added to this complexity is the number of variables the Utilities prepare (sic) to make between IRPs -- "as discussed above," in parentheses -- that are changed at the discretion of the Utilities and do not -- and not properly vetted by the Commission or parties.

And there you're talking about the IRP. Is that correct?

A. Yes.

Q. Are you aware that the IRP process is open to the public?

A. Certainly.

Q. Have you ever participated in any of the Utilities' IRP open meetings?

A. I've never been on a board, but I have certainly sat in numerous IRPs for Idaho Power. I can't think whether I've ever been to an Avista, but I've certainly been in the audience during the Idaho Power IRP process.

Q. And you've had an opportunity to comment in those proceedings?

A. You comment, sure.

Q. Okay.

MR. ANDREA: That's all I have. Thank you.

COMMISSIONER SMITH: Mr. Walker.

MR. WALKER: Thank you, Madam Chair.

CROSS-EXAMINATION

THE WITNESS: Now I'm ready.

Q. BY MR. WALKER: All right. Good afternoon, Dr. Reading. I'd like to follow up on something that

Mr. Andrea touched on, and this is found on page 7 --

A. Of direct?

Q. -- of your direct, and also in a general sense the several pages leading up to seven as well, essentially the first several pages of your testimony where I know we've had a lot of talk of Orders and reference to Commission Orders, and you talk about some old Orders from the '80s and generally talking about the SAR. And then ultimately on page 7, you have a statement that Mr. Andrea asks you about where you say the SAR has produced avoided cost rates that have proven to be remarkably accurate in hindsight?

A. Yeah.

Q. And did you review any other Commission Orders perhaps from this case or ones that may be more current than those that you cited with reference to that particular issue?

A. I certainly have read several Orders with respect to this case. I believe the Chairman of the Commission -- I'm trying to -- what case preceded this? Anyway, Madam Chairman indicated that the Commission had decided that the rates were out of whack, and therefore we need to have a hearing.

And I might add that -- well, if I may expand a little: One of the things that I find curious in this case is that we're talking about avoided cost price. In fact, I think, Mr. Donovan (sic), you were quoted in the Press-Tribune this morning as saying this case is about the proper price, and I assume AP quoted you correctly.

If we're just dealing with price and natural gas prices are a major driver and we agree with this, it would make more sense, to me, that the Utilities would come in and say, Hey, wait a minute, given the established methodology, the SAR, that we need to do something about avoided cost prices because they are too high given natural gas prices. And I believe for more than two years that avoided cost prices are out of whack relative to natural gas prices right now.

What I found curious about this case is that it should be about price, but price isn't who owns the RECs, price isn't 20 year versus five years. Price isn't interruptibility. Those aren't elements that deal with price. And they deal more with, my personal view, the dismantling of the independent power producer -- producing industry in Idaho, which I think should remain viable in the long run for the benefit of the ratepayer.

Q. And, nevertheless, you're of the view that the SAR produces remarkably accurate rates?

A. Yep.

Q. And are you aware of this Commission's finding of -- in this matter, GNR-E-11-03? This is from Order 32498 in this proceeding issued in March of this year where the Commission specifically found, and I quote: Methodologies previously approved by this Commission as utilized and applied by Idaho Power do not currently produce rates that reflect Idaho Power's avoided costs, and are not just and reasonable nor in the public interest.

A. Yes, and that was what I was referring to about Madam Chairman stating essentially that from the Bench.

As I attempted to say a little while ago, that if that is the problem is the price, that is not necessarily the SAR methodology. It is the application, in my opinion, of the SAR that it wasn't maintained to reflect current conditions through time in this particular period when gas prices are at historic lows.

Q. And you've -- you testified on cross earlier today that and it's no secret to any of us that appear at the Commission here that you've been around the Commission and PURPA things for its entire existence here in Idaho. Is that correct?

A. Yes, from its -- I was at the Commission, I was on the Commission Staff, when the original Orders establishing avoided cost, PURPA, et cetera, were being debated and decided by the Commissioners.

Q. And would you accept if I told you there's evidence in the record that Idaho Power has approximately 119 contracts with QF projects?

A. That sounds about right to me.

Q. And, Mr. Reading, based on your experience, do you have any idea of how many of those contracts are based on an SAR-based methodology?

A. I assume all of them.

Q. Pretty close. Would you accept if I said it was all of them except maybe three?

A. I will yield, but, yeah, the vast majority, certainly.

Q. So would it be fair to say that what the Commission was referencing in that Order when it found that those rates were not just and reasonable nor in the public interest, it's really talking about rates that were established under that methodology?

A. Yes. And I would repeat that methodology -- that it's not the methodology, it's the drivers of the methodology; and that given current gas prices, it's producing too high a rate.

Q. So when we talk about what the Commission's obligation under Federal law is with implementation of PURPA, it's not necessarily to establish a methodology, is it?

A. My understanding is the Commission -- under PURPA, the Commission has very wide discretion in determining avoided cost rates that include the methodology that's used, be it the proxy or the differential revenue requirement or the peaker method, that they have the discretion to do that. And as your witness referenced, a study that was done by NERA shows that various Commissions have decided that for their state, different methodologies are valid.

Q. And so could you say that these are all ways that various Commissions or that this Commission could choose to set the avoided cost? Isn't that what their duty really is, to establish avoided cost?

A. In the public interest, yes.

Q. Okay. And methodology is simply a vehicle that's utilized to try to get at what the avoided cost should be set at. Right?

A. Yes.

Q. And you're aware, are you not, that Federal Regulations define what avoided cost is or should be?

A. To the extent I understand the legalese in those, yes. It's to determine what the accurate, true, best, what the Utility -- what the avoided cost is, and that the key phrase I pull out of that is where customers are indifferent to whether the Utility builds a resource or whether the power is supplied by the QF.

Q. Thank you. I think customer indifference, I would agree, is an important portion.

You testified about something about the 20-year cost of a Utility-owned resource. Is that found anywhere in the definition of what avoided cost is?

A. I have not -- I do not recall that in the Federal

Regulations the length of the contract is mentioned anywhere. I would, from my reading of the FERC Regulations and the meaning of PURPA, is that independent power should be encouraged; and in my mind, unless independent power can get sufficiently long contracts, then that is discouraging, not encouraging.

Q. Thank you, Dr. Reading. And that was maybe an inartful question. I wasn't intending to ask about the length, more of the components of the avoided cost.

And does it make sense to you, does it ring a bell, that avoided costs are defined as incremental costs to the Electric Utility?

A. Yes.

Q. And the definition, does it ring a bell that that definition specifically references incremental cost that that Utility may incur either by generating electricity itself or by making a purchase but for the addition of that QF energy?

A. Yes. And, again, without -- you should never have a witness that used to be a teacher -- without putting my hat on as an economist. Economics profession draws some pretty, I think, unmeaningful differences between avoided cost, incremental cost, marginal cost, et cetera, and there is a wide variety of ways one can define incremental cost.

In general, marginal cost is an infinitesimally small, over a time period, change in rates. Incremental cost is a longer ban of the cost change, and that's what we're talking about here. An incremental cost, to me, as an economist, has a time dimension.

Q. So, Dr. Reading, in review of your testimony, especially your direct testimony, correct me if I'm wrong, but there's a recurring theme where you refer numerous times to putting a QF on equal footing with a Utility or a Utility-owned resource. Is that not a fair characterization?

A. That's a very fair characterization.

Q. So it's fair to say that that's your view of a proper avoided cost where you would treat a Utility and a QF the same as far as pricing and recovery of costs?

A. Yes.

Q. And you don't see any difference in those two entities and the way their costs are or should be recovered?

A. I guess I missed the last one. A Utility's resource has a different recovery mechanism in that it gets -- when it's approved by the Commission, it gets its capital costs put in rate base and its variable cost is run, at least in this jurisdiction, through a production cost adjustment; whereas, a QF receives a rolled-in capacity and energy payment per kWh over time. So the recovery mechanisms are different. The important thing is -- is that the best of our ability, we have the ending result of those prices the same.

Q. And, Mr. Reading, you offer your testimony in this proceeding on behalf of Clearwater, Simplot, and Exergy?

A. That is correct.

Q. And those are -- would those represent QF developers on each of the three Utilities? Is that --

A. Yes.

Q. Okay. So can you tell us -- can you tell me what the -- what the authorized rate of return is for any one of those, any one of their developed QF projects?

MR. RICHARDSON: Madam Chair, I'll object. That's confidential information, internal QFs, that the Utility is not allowed to inquire into under federal law.

COMMISSIONER SMITH: Mr. Walker.

MR. WALKER: Can Mr. Reading tell me the answer to that or not?

MR. RICHARDSON: Madam Chair, I'll continue my objection that Dr. Reading not be allowed or forced to answer the question.

COMMISSIONER SMITH: So let's here the question again.

MR. WALKER: I asked if he could tell me the allowed rate of return for any of his clients' QF projects in Idaho.

MR. RICHARDSON: Madam Chair.

COMMISSIONER SMITH: But they're not regulated, Mr. Walker, so I don't understand the question.

MR. WALKER: Okay.

Q. BY MR. WALKER: Is the rate of return of a Utility something that's known and regulated by this Commission?

A. Yes.

Q. And I guess the point is the rate of return of a QF is something that's not?

A. That is correct, because the PURPA industry and QFs only meet the obligation that they are afforded the full avoided cost of the Utility.

We live in a red state. Competition is a good thing. That's one of the things that I like about the QF industry. If a independent developer, under PURPA, can go out and produce electricity cheaper than the Utility can produce it but at the same cost, then that's good for everybody. And if I was a Utility and that was my belief, then I'd want to know what those other guys are doing to be able to produce electricity and make more money than I am.

Q. But isn't it true that the QF really doesn't want to be treated just like the Utility for purposes of regulation, does it?

A. Other than regulation of avoided cost, no.

MR. WALKER: No more questions, Madam Chair.

COMMISSIONER SMITH: Thank you, Mr. Walker.

Do we have questions from the Commission?

COMMISSIONER REDFORD: No.
COMMISSIONER KJELLANDER: I do not.

EXAMINATION

BY COMMISSIONER SMITH:
Q. I have one, Dr. Reading. I just have to make sure I heard correctly, because sometimes you think you hear something but you don't.
A. Sometimes you think you say something and you don't, Madam Chair.
Q. That's true too. So in response to a question by Ms. Sasser, I thought I heard you say that before RECs existed --
A. Yes.
Q. -- the only way that a PURPA project was financially viable was if the Commission set avoided cost rates way too high. Did I hear that correctly?
A. If I said that, I will deny at this point that I said it, and I certainly do not mean it.
Q. Okay. Well, I -- you know, I wrote it down because I was amazed and --
A. No, I do not believe that. I guess go back and look at the record and --
Q. All right.

A. I would correct the transcript if I saw that.
Q. Okay. All right. Yeah, I think that -- I think that's my only question.
I did note on pages 56 and 57, you talked about the Montana Public Service Commission rejecting a request by NorthWestern Energy to include an economic curtailment provision in future QF contracts?
A. Yes.
Q. And do you know if NorthWestern owns any generating resources?
A. I guess I do not.
Q. Would you be surprised if the answer was no, they do not, because in their infinite wisdom --
A. -- they sold? When it was Montana Power, they sold it off and went into telecommunications?
Q. Yes.
MR. UDA: Madam Chair, for the record, I practice in front of the Montana Public Service Commission, and I can tell you NorthWestern does, in fact, own generating resources. And, in fact, they just acquired a 40-megawatt wind project called Spion Kop.
COMMISSIONER SMITH: Well we're swear you in, Mr. Uda.
MR. UDA: Sorry. I just want to make sure everybody was on the same page.

COMMISSIONER SMITH: Any redirect, Mr. Richardson?

MR. RICHARDSON: I do have a couple, Madam Chair.

COMMISSIONER SMITH: I warned you about your lawyer. Remember this.

REDIRECT EXAMINATION

BY MR. RICHARDSON:

Q. Dr. Reading, you were asked about the $45 liquidated security provision?

A. Yes.

Q. And you were asked if it were arbitrary or excessive. But did you address that in your testimony on page 39, suggesting that it should be a mark to market?

A. Yeah, that would be a rational way to come to that. And as I remember, that was Mr. Schoenbeck had the same thing in his testimony.

Q. So the $45 number may just, by accident, happen to equal what a Utility's damages were, but you can't predict that?

A. Right, more or less, yes.

Q. And when Ms. Sasser was asking you about your "PURPA killing" remark, did you have a chance to fully answer that question, or I thought maybe you had more?

A. What I attempted to say was that -- that the collectivity of what I see as part of this hearing and what is recommended by the Utilities, and especially Staff because they sort of brought them all together, in total would be PURPA killing. One could peel off one of those things maybe and say it is or it isn't, but as a collectivity, it certainly would be. And some of them, I think -- for instance, as I said in my testimony, moving from 20 years to five years by itself would be a PURPA killing.

Q. And you were asked by both -- two of the IOUs here about your comment that SAR has been remarkably accurate over time?

A. Yes.

Q. And that's the key to that statement is "over time." At any one point in time, it may or may not be remarkably accurate?

A. Yeah, that is correct. And on one side of the coin, you could look to what the avoided costs were during the run-up in prices when they went $1,500 a megawatt hour or whatever when they were significantly low, to what I thought I was trying to say here in the last couple years anyway, they have certainly been, I think, too high.

And as I stated, the way to solve that problem is not to dismantle the QF industry, but work within what is there and try to make adjustments.

Q. And it's not a coincidence that the SAR is a combined cycle combustion turbine and that just happens to be what Idaho Power just brought online this summer?

A. Just brought on, yeah, yep.

Q. And you were asked about QFs producing capacity. Isn't it reasonable to consider all QFs collectivity as a capacity-producing plant?

A. Yes, and as a collectivity reliable high -- as a togetherness, high reliability factors or capacity factor.

And another reliable advantage is -- is they are geographically dispersed and so they are putting kilowatt hours into the system over a wider range.

Q. And you were asked about the five-year contract period, signing a contract five years before operation. And I asked Mr. Kalich this question yesterday about what his business professor would say to signing a five-year contract without knowing what the price would be for three years into it, and since you're a professor, I get to ask you: What do you think of that?

A. Well, I think I explained it. If it was me, I would have, I think, a discussion -- which we do -- with Mr. Kalich that you couldn't get financing if you didn't know the price. The bankers need some assurity that they're going to receive revenue enough to cover whatever mortgage or installment payments the QF has to make.

Q. And, lastly, you were asked about the IRP process and whether or not you participated.

A. Yes. And I said -- they asked me if I made a comment, and I said, yes, I sit in the audience, raise my hand to make a comment.

Q. Can you tell us your experience, if you recall, in doing work for the Industrial Customers of Idaho Power in the IRP process in an attempt to get Idaho Power to consider using backup generation as a peak load resource?

MR. WALKER: Object: That's leading and beyond the scope of his cross.

Q. BY MR. RICHARDSON: Can you explain to me some more detail of your experience in the IRP process, Dr. Reading?

A. Yeah, the IRP process, as I explained I thought in my testimony, was that it needs greater vetting. We talked about my history from the beginning here. The IRPs or planning documents didn't mean very much 20 years ago. Now, especially, IRPs are being used to decide a myriad of very important decisions for a regulated Utility. Avoided cost is just one of them. Justifying DSM is one of them. Planning what the next resource should be is one of them.

And what I find sort of I guess curious about it is -- is the Utilities have come in and said this is -- you know, everybody can get in the room and everybody can comment, and so it's a collaborative.

I have two comments on that, I think:

One is that Utility regulation and planning is an insider's game, and most of the individuals that I see on the advisory committees, et cetera, are not -- they -- in fact, one of our clients, Don Sturtevant from Simplot, he's not into the various models of load forecasting, et cetera, so I think that -- or how transmission systems are put together. So it's a fairly complicated process.

The other thing I find curious is the Utilities come in and say, This is great, this is collaborative, we're all together, everybody can sign off on it; and then before the ink dries on the Commissioners' signatures on the accepting Orders, they want to change the gas price, they want to change the forecast loads, they want to change everything in between.

And those two -- that doesn't mesh with me. That is not a consistent view of how the system works.

Q. So you wouldn't set avoided cost rates based on an IRP methodology, would you?

MR. WALKER: Objection: That is beyond the scope of cross, and leading and improper.

MR. RICHARDSON: That's all I have, Madam Chair.

COMMISSIONER SMITH: And, fortunately, we have this wonderful process, so --

MR. RICHARDSON: I have nothing further for

Dr. Reading.

COMMISSIONER SMITH: Thank you, Dr. Reading.

THE WITNESS: Thank you. I made it. Goddamn.

COMMISSIONER SMITH: You made it.

THE WITNESS: Goddamn.

MR. RICHARDSON: May Dr. Reading be excused, Madam Chair?

COMMISSIONER SMITH: He may.

THE WITNESS: Thank you. You won't excuse me.

(The witness left the stand.)

COMMISSIONER SMITH: All right. We're going to take a break until three o'clock, and when we come back, we will either start with the Staff witnesses, or we will do Mr. Sorenson or Mr. Hansten if they are here and would like to be taken. So, see you at 3:00.

(Recess.)

COMMISSIONER SMITH: So welcome back.

Ms. Sasser, I believe we're ready for your witnesses.

MS. SASSER: Thank you, Madam Chair. Staff calls Dr. Cathleen McHugh to the stand.