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BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

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

REBUTTAL TESTIMONY OF RICK STERLING

IDAHO PUBLIC UTILITIES COMMISSION

JUNE 29, 2012

Q. Please state your name and business address for the record.

A. My name is Rick Sterling. My business address is 472 West Washington Street, Boise, Idaho.

Q. By whom are you employed and in what capacity?

A. I am employed by the Idaho Public Utilities Commission as the Engineering Supervisor.

Q. Are you the same Rick Sterling who previously submitted testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony in this proceeding?

A. The purpose of my rebuttal testimony is to address the direct testimony of Richard Guy of Idaho Wind Partners I, LLC and the direct testimony of Don Schoenbeck, witness for the Twin Falls and North Side Canal Companies and the Renewable Energy Coalition as their testimonies relate to 18 C.F.R. 292.304(f) ("Section 304(f)"), the FERC rule implementing PURPA that deals with curtailment under certain circumstances.

Q. Do you agree with Mr. Guy's and Mr. Schoenbeck's interpretations of Section 304(f)?

A. No, I do not.

Q. Please explain why you believe their interpretations of Section 304(f) are incorrect.

A. On pages 4-6 of Mr. Guy's testimony, he discusses Section 304(f) and states that it is his understanding, based on FERC Order No. 69, that Section 304(f) does not apply to QF contracts with fixed rates. Similarly, Don Schoenbeck, on pages 36-42 of his direct testimony, also contends that Idaho Power's proposed Schedule 74 is not consistent with FERC's view on QF curtailment.

For reference, 18 CFR 292.304(f) states the following:

> (f) *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.[1]

FERC's Order No. 69, in explaining the intent of Section 304(f), stated the following:

> The Commission does not intend that this paragraph override contractual or other legally enforceable obligations incurred by the electric utility to purchase from a qualifying facility. In such arrangements, the established rate is based on the recognition that the value of

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[1] (Parts (2), (3), and (4) of this section have been omitted because they relate to notification requirements not relevant to this discussion).

the purchase will vary with the changes in the utility's operating costs. These variations ordinarily are taken into account, and the resulting rate represents the average value of the purchase over the duration of the obligation. The occurrence of such periods may similarly be taken into account in determining rates for purchases.[2]

A. Just recently, FERC went on to further explain the proper application of Section 304(f) when it stated the following:

55. In Order No. 69, which implemented section 304(f), the Commission stated that that section was intended to deal with a certain condition which can occur during light loading periods, in which a utility operating only base load units would be forced to cut back output from the units in order to accommodate the unscheduled QF energy purchases. The Commission stated that such base load units might not be able to later increase their output levels rapidly when the system demand later increased, resulting in the utility needing to rely upon less efficient, higher cost units. Section 304(f), when read in conjunction with the relevant explanation in Order No. 69, applies only to such low loading scenarios, and cannot be relied upon to curtail purchases of unscheduled QF energy for general economic reasons.

56. Many avoided cost rates are calculated on an average or composite basis, and already reflect the variations in the value of the purchase in the lower overall rate. In such circumstances, the utility is already compensated, through the lower rate it generally pays for unscheduled QF

[2] FERC Order No. 69, Docket No. RM79-55, *Final Rule Regarding the Implementation of Section 210 of the Public Utility Regulatory Policies Act of 1978,* (Issued February 19, 1980), p. 77.

> energy, for any periods during which it purchases unscheduled QF energy even though that energy's value is lower than the true avoided cost. On the other hand, for avoided cost rates that are determined in real-time, such avoided costs adjust to reflect the low (or zero or negative) value of the unscheduled QF energy, allowing the QF to make its own curtailment decisions. In neither case is the utility authorized to curtail the QF purchase unilaterally.[3]

It is noteworthy that FERC, in paragraph 55 of the *Entergy* Order recognized that "Many avoided cost rates are calculated on an average or composite basis, and already reflect the variations in the value of the purchase in the lower overall rate." (Emphasis added). Furthermore, FERC stated "In such circumstances, the utility is already compensated, through the lower rate it generally pays for unscheduled QF energy, for any periods during which it purchases unscheduled QF energy even though that energy's value is lower than the true avoided cost." (Emphasis added).

Mr. Guy's and Mr. Schoenbeck's interpretations of the proper application of Section 304(f) might be correct if the presumptions described by FERC in Order No. 69 and in the *Entergy* order were correct for Idaho. However, those presumptions, in fact, are not correct

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[3] *Entergy Services, Inc.*, Docket Nos. ER05-1065-011, OA07-32-008; 137 FERC ¶ 61199 (F.E.R.C.) *Order on Compliance Filing* (Issued December 15, 2011).

for Idaho.

I have been the person responsible for computing Idaho's published avoided cost rates for the past 18 years. Although I did not create the original SAR model used to compute published avoided cost rates, I have made the extensive changes to the model that have been ordered over the past 18 years, I have maintained the model, and I have been responsible for making all of the avoided cost computations adopted by the Commission since 1995. Based on my extensive experience with the SAR model, Idaho's published avoided cost rates <u>do not</u> already reflect the variations in the value of the purchase in the lower overall rate <u>during the specific low loading scenarios when 304(f) is clearly intended to apply</u>.

It is true that Idaho's avoided cost rates may at times be either higher or lower than the true avoided costs, but this is due to real-time prices not exactly matching rates computed in advance for a long-term contract. This fact is simply an unavoidable outcome of the computation methodology, not an input assumption that explicitly drives the result. Frequent deviations between real-time prices and computed long-term avoided cost rates are inevitable under any computation methodology, regardless of whether any attempt is made to account for low loading scenarios.

Under the SAR methodology for computing published avoided cost rates, the method is based solely on the estimated cost of building and operating a CCCT, the surrogate avoided resource. There is clearly no attempt to model low loading scenarios, or for that matter, any other load scenarios. Furthermore, there is no consideration for operational circumstances or constraints of either the QF or the utility's other generation resources, nor is there any attempt to reflect actual variations in the value of the purchase in a lower overall rate. Quite simply, the SAR methodology considers only the CCCT surrogate, independent of any other resources and system conditions, and assumes that it will be operated during all hours when it is available.

All 11 of the projects owned and operated by Idaho Wind Partners have contracts containing published avoided cost rates computed using the SAR methodology. Therefore, there is no consideration in the rates in any of these contracts for low loading conditions when curtailment would be likely.

Q. Once avoided cost rates have been computed by the SAR model, are there post-modeling adjustments applied to the rates to attempt to shape them to better match variations in true avoided costs?

A. Yes, two types of adjustments are made. One adjustment is made to shape the rates by season and the other adjustment is made to shape the rates based on heavy and light load hours.

Q. Please explain the seasonal adjustment.

A. The avoided cost rates computed by the SAR model consist of single annual values corresponding to each year of the proposed contract. The purpose of seasonal rate adjustments is to shape annual rates into seasonal rates that better reflect variations in value during different times of the year. For example, power is typically more valuable during peak summer and winter months, and less valuable during spring months when hydro generation is cheap and plentiful. Seasonalization factors are applied to the avoided cost rates computed by the SAR model to either increase or decrease the rates during different seasons. Seasonalization factors are applied as weighting factors. For Idaho Power for example, a seasonalization factor of 1.20 is applied in the months of July, August, November and December, thereby increasing rates by 20 percent in the utility's summer and winter peak load months. Conversely, in the months of March - May, a seasonalization factor of 0.735 is applied to lower avoided costs during the spring runoff period. During the remaining months of the year (January, February, June, September and October), a seasonalization factor of 1.00 is applied. For Avista, seasonalization factors are applied in only two different seasons of the year. For PacifiCorp, seasonalization factors are applied monthly.

Q. Please explain the heavy and light load hour adjustment.

A. The purpose of the heavy and light load hour adjustment is to shape seasonal (or monthly) rates into hourly rates that better reflect variations in value during different times of the day. Heavy load hours are those hours from 7:00 am through 11:00 pm Monday through Saturday. Light load hours are the remaining nighttime hours and all hours on Sundays and holidays. A Commission-approved differential between heavy and light load hour prices is applied to rates calculated by the SAR model such that prices in heavy load hours are increased and prices in light load hours are decreased. There is no overall impact of the heavy/light load price differential on projects with the same flat hourly generation shape; however, facilities that produce more or less of their generation in heavy or light load hours receive payments accordingly. The current approved heavy/light load hour price differential is $5.00 per MWh for Avista, $7.28 for Idaho Power, and varies on a monthly basis for PacifiCorp.

Q. Do either of the seasonal adjustments or the heavy/light load hour adjustments account for the type of variation in price or the low load scenarios contemplated by the *Entergy* Order?

A. No, they do not. The seasonal and heavy/light load hour adjustments are solely intended to recognize that the value of power generally varies throughout the months of the year and throughout the hours of the day. Because the SAR model only computes annual rates, both of these adjustments help to shape the rates to more closely match expected variation in actual market prices. Clearly, however, they do not consider the dispatch of any of the utility's resources, the actual real-time variations in the value of power, or the utility's inability to further back down base load resources or its ability to ramp them back up to meet increasing load. In short, these adjustments are in no way intended to address pricing during those low load situations when the utility might be forced to curtail generation.

Q. Are there any other adjustments that are made to the avoided cost rates computed by the SAR model?

A. Yes, there is one additional adjustment that is applied only to wind projects. That adjustment is a wind integration adjustment that serves to decrease avoided cost rates for intermittent wind generation. The purpose of the wind integration adjustment is to account for the additional costs experienced by the utility when it must integrate wind generation with the generation produced by its other generation resources. The additional costs attributable to intermittent wind generation are primarily the result of non-economic dispatch of the utility's other resources. Wind integration costs adopted by the Commission vary from seven to nine percent of the avoided cost rate depending on the level of wind penetration on each utility's system, and are capped at $6.50 per MWh.

Q. Do wind integration adjustments account for the type of variation in price contemplated by the *Entergy* Order?

A. No, they do not. Wind integration adjustments are generally determined through sophisticated studies that measure the additional incremental costs incurred by the utility as increasing amounts of wind generation are added to the system. The studies typically involve hourly dispatch modeling of the utility's entire resource portfolio. The hourly dispatch simulations attempt to replicate normally expected conditions, not extreme low load circumstances when all base load resources are backed down to minimum levels. In fact, the hourly dispatch models typically used for wind integration studies do not have the ability to curtail QFs. Therefore, wind integration adjustments do not account for the type of variation in price and the low load scenarios contemplated by the *Entergy* Order.

Q. Eight of the eleven Idaho Wind Partners contracts contain what is sometimes referred to as the "90/110" provision. Can you explain what this provision is and whether it relates to price variations contemplated by the *Entergy* Order?

A. The 90/110 rule was adopted in 2004[4] when the first large scale wind QF contracts were proposed. With the emergence of large wind projects, a question arose about whether wind facilities, because of their intermittent generation, should be entitled to published avoided cost rates. Up until this time, utilities had held that published rates were intended for "firm" generation that was reasonably predictable. As a condition for being eligible for published rates, the utilities proposed that the generation from all new facilities be subject to a requirement that the monthly generation be predictable within a 90 to 110 percent

[4] Case Nos. IPC-E-04-08 and IPC-E-04-10, Order No. 29632, November 22, 2004.

band. If the project could deliver an amount of energy that was at least 90 percent of its monthly estimate but not more than 110 percent of the estimate, it was entitled to full published avoided cost rates. However, if the facility's actual monthly generation fell outside of the 90/110 percent band, it would be entitled to a market-based rate for the shortfall or the excess generation. The purpose of the 90/110 rule was to require a reasonable level of predictability for QFs, comparable to the predictability a utility could expect if it purchased power from some other source.

The 90/110 rule was later abandoned for wind projects and replaced with three new requirements intended to accomplish a similar goal. Three of Idaho Wind Partners' eleven projects contain these new requirements. Under the new requirements, in order to be eligible for published rates, wind projects must maintain a "Mechanical Availability Guarantee" of 85 percent, must agree to pay a proportionate share of wind forecasting costs, and must agree to a wind integration charge as discussed earlier. As with the 90/110 rule, these three new requirements are intended to ensure a reasonable level of predictability in order for wind projects to be entitled to "firm" or published avoided cost rates. The purpose of these requirements is not to account for the type of variation in price based on curtailment contemplated by the *Entergy* Order.

Q. What can you conclude about curtailment from the way published rates are calculated and from the other elements contained in the power sales agreements?

A. I conclude that nothing in the SAR model in any way captures the variations in an overall rate that would encompass circumstances described in FERC Order 69 or in the *Entergy* Order. Furthermore, none of the provisions contained in any of the Idaho Wind Partners' contracts (or any other QF contracts) address or capture variations in an overall rate that would encompass circumstances described in FERC Order 69 or in the *Entergy* Order.

Q. Could the SAR model be modified to consider the low load scenarios described in FERC Order 69?

A. No, I do not believe that it could be. Modeling load scenarios would require far more sophistication than the current SAR model possesses. An SAR model, because it is based on the costs of building an operating a single, surrogate resource, is not capable of considering load scenarios. I believe that it would be necessary to have a model with resource dispatch capability in order to model various load scenarios.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 29TH DAY OF JUNE 2012, SERVED THE FOREGOING **REBUTTAL TESTIMONY OF RICK STERLING,** IN CASE NO. GNR-E-11-03, BY E-MAILING AND MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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