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

IN THE MATTER of Application for Approval of Avoided Cost Tariff Schedule QF-1	UTILITY DIVISION DOCKET NO. D2016.5.39

PREFILED REBUTTAL TESTIMONY OF ROGER SCHIFFMAN ON BEHALF OF FLS ENERGY AND CYPRESS CREEK RENEWABLES

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Roger Schiffman. My business address is 1701 Arena Drive, Davis, CA 95618.

Q. BY WHOM ARE YOU EMPLOYED?

A. I am the managing director of Power Markets Research Group ("PMRG"). PMRG is a private consulting firm specializing in energy markets, resource planning issues, and in calculating estimates of long-term avoided costs. I started that position after seven years with Black and Veatch Corporation in Sacramento, California.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATION.

A. I received my bachelor of business administration, finance, investment and Banking in 1988 from the University of Wisconsin-Madison. I continued my studies at the University of

Wisconsin-Madison working toward a Master of Science in Finance from 1988-May 1990. I left the graduate studies program to join the Wisconsin Public Service Commission, where I became a senior financial analyst.

Q. PLEASE BRIEFLY DESCRIBE YOUR WORK HISTORY.

A. Prior to my assignment as manager at PMRG, I was a principal at Black and Veatch and assisted in directing, preparing and developing market analysis, integrated resource planning, nodal market planning, avoided cost, transmission planning, transmission congestion, other transmission issues, resource planning/power supply analyses, and generation reliability analysis. I have provided consulting services in energy market analysis, utility resource planning, and power price forecasting for the last 18 years, at consulting firms including Henwood Energy Services, Navigant Consulting, Ventyx, and Black & Veatch. At each of these firms, I have been responsible for developing long-term projections of electricity prices in U.S. wholesale markets. Those projections have been used in developing estimates of avoided cost, in utility integrated resource planning, and in supporting valuation and due diligence review of purchase and sale transactions for individual power plants, and for portfolios of power plants. At PMRG, I have continued my work on these subject matter areas.

Q. HOW MANY YEARS HAVE YOU BEEN WORKING ON UTILITY RESOURCE PLANNING AND UTILITY RESOURCE/AVOIDED COST ESTIMATES?

A. I have more than 25 years of experience working in the public and private sectors directing, preparing and developing reports and testimony on market analysis, integrated resource planning, nodal markets, avoided cost, transmissions, resource planning/power supply analyses, and generation reliability analysis.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I was retained by FLS Energy and Cypress Creek Renewables ("FLS" & "Cypress") to analyze NorthWestern Energy's ("NorthWestern" or "NWE") avoided cost estimates for the QF-1 tariff. I was also retained to create an independent avoided cost forecast which, in my estimation, more accurately captured NWE's long-term avoided cost.

Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE THE MONTANA PUBLIC SERVICE COMMISSION?

A. Yes. In April, 2016, I filed written testimony with the Montana PSC related to long-run avoided cost for the Greycliff Wind project, and on May 31, 2016, I testified at hearing, in front of the Commission.

Q. CAN YOU SUMMARIZE THE RESULTS OF YOUR INVESTIGATION AND ANALYSIS?

A. Yes. NWE has developed a set of projected avoided costs for its system that it proposes to use as a pricing offer for the purchase of energy from QF-1 resources. PMRG reviewed the NWE avoided cost projections and methodology, to determine if the approach taken is consistent with industry best practice and if it is consistent with Commission avoided cost decisions. The discussion which is set forth below in detail highlights key findings of that review, and also seeks to quantify areas where adjustments to NWE's methodology are appropriate.

Based on the review described below, PMRG has concluded that there are a number of deficiencies in the NWE avoided cost methodology, its specific application to QF-1 resources, and the data assumptions used. These aspects result in the NWE estimates being below its actual avoided cost for QF-1 resources.

Q. CAN YOU SUMMARIZE FROM YOUR PERSPECTIVE THE HISTORY AND REQUIREMENTS OF PURPA AS IT RELATES TO AVOIDED COST?

A. Yes. The concept of Avoided Cost has its roots in the Public Utilities Regularly Policies Act ("PURPA") passed by Congress in 1978. PURPA was instituted when the nation's power

generation relied heavily on imported oil that had undergone significant price volatility. Significant increases in the cost of new power plants and the general feel that the traditional utility model was failing to foster an environment of competition also led to general dissatisfaction with the utility model in the United States during the 1970s. Consequently, Section 2(1) of PURPA explained that the purpose of the act was to further the goals of conserving electric energy, increasing utility efficiency, and achieving fair rates for utility customers. The concept was to achieve these goals through policies that would foster the development of non-utility cogeneration and small power production.

Under Section 210 of PURPA, a utility is required to purchase electricity from certain nonregulated power producers, termed qualifying facilities ("QFs"). A QF can be either a cogeneration facility meeting certain efficiency requirements, or a small power producer (80 MW or less) whose energy input was primarily from waste, biomass, or renewable resources (the size limitation has since been removed).

PURPA requires utilities to purchase QF power at a nondiscriminatory, just and reasonable rate that does not exceed the purchasing utility's avoided cost. This avoided cost is an upper limit on purchases and is defined in Section 210 (d) as "the cost to the electric utility of the electric energy which but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source." A utility's full avoided cost includes incremental costs of electric energy, capacity, or both that, if not for the purchase from the QF, the utility would purchase or generate itself.

Q. PLEASE SUMMARIZE FERC'S GUIDANCE TO STATE REGULATORY COMMISSIONS IN ESTABLISHING AVOIDED COST.

A. The FERC rules implementing PURPA did not select a specific method for establishing the avoided cost rate to be paid QFs but rather left the specific methodology to the discretion of

each state. However, FERC has also made it clear that any methodology adopted by the individual states must be consistent with FERC's implementing regulations. FERC also provided certain guidelines to states to consider when developing avoided cost rates. These include:

1. Utilities can be required to pay QFs for the "capacity value" of their projects only when the availability of such capacity allows the utility to reduce its own capacity-related costs by deferring construction of a new plant or by deferring commitments to firm power purchase contracts.
2. Utilities can be required to pay capacity payments even if the QF provides electricity only on an "as available" basis. In such cases, calculation of the payment would be based on a probabilistic estimate of production from a large number of similar QFs.
3. Avoided capacity costs based on a plant designed to displace less efficient generating units must be adjusted to take into account the lower operating costs the utility would incur with the new plant. Thus, if a new plant is deferred by virtue of QF purchases, fuel savings also would be forgone and these "lost savings" should be reflected in the rate paid to the QF.
4. The avoided capacity and energy costs used to calculate QF purchase rates must be internally consistent. For example, to use the high capacity cost of a deferred base load unit and the high energy cost of a peaking unit would exceed the utility's true avoided costs.
5. The just and reasonable rate for new capacity is the avoided cost even when the utility making the purchase is simultaneously making sales to the QF.
6. Rates for QF purchases may be levelized over the term of the obligation as long as the total payments over time do not exceed the estimated avoided cost. Rates may be negotiated at levels below full avoided costs if the QF agrees to the arrangement, presumably in return for some contractual provisions not mandated under the applicable rules in that jurisdiction.

Q. APART FROM THIS GENERAL GUIDANCE, DO FERC'S REGULATIONS PROVIDE GUIDANCE?

A. Yes. 18 C.F.R. § 292.304(e) provides a list of factors that a state Commission must consider when calculating the energy and capacity components of avoided cost rates. These factors include:

1. Avoided cost data submitted by utilities to state regulatory authorities.
2. Availability and characteristics of the QF's power during system peak periods including:

a. The utility's ability to dispatch the QF
b. QF reliability
c. Duration and enforceability of a utility's contract with a QF
d. Ability to schedule QF outages in coordination with the utility
e. Usefulness of QF production during system emergencies
f. Aggregate value of QF capacity and energy on a utility system
g. Smaller capacity increments and shorter lead times associated with QF capacity

3. The relationship between a QF's production and a utility's ability to actually avoid costs.
4. Costs or savings from changes in line losses as a result of QF purchases.

Q. WHAT HAVE STATES DONE AS FAR AS IMPLEMENTING FERC'S AVOIDED COST GUIDANCE AND REGULATIONS?

A. States have adopted a wide variety of approaches in implementing FERC's directives and in establishing avoided cost methodologies. States have addressed the following conceptual issues:

1. Whether short or long-run marginal costs should form the basis for the avoided cost analysis.
2. The appropriate planning horizon and incremental block of output over which costs are to be measured.
3. The particular methodology used for computing the relevant marginal costs.
4. The treatment accorded to small increments of QF capacity that have no impact individually on a utility expansion plan but that could have an impact if there were a large number of smaller QFs.
5. Treatment of firm versus non-firm QF purchases.

These conceptual issues have been the basis for the varying approaches that Commissions have adopted, including:

1. Long-run marginal cost methods.
2. Proxy unit approaches (in which avoided capacity and energy cost payments are linked to a unit selected to represent the next unit on the system, perhaps without a detailed analysis confirming that the proxy unit is the best fit for the system).
3. Expansion planning analysis (in which avoided capacity and energy costs may be linked to the next unit on the system as identified through a generation expansion planning study).
4. Short-run marginal cost methods.

5. Single unit approaches (generally this involves identifying the unit on the dispatch margin and linking avoided energy cost payments to the production cost of that unit).
6. Incremental heat rate approaches (linking payments to the incremental heat rate on a utility system that may involve more than a single unit).
7. Production costing approaches (using a computer simulation to identify the production cost and avoided cost payments).
8. Purchased power approaches (in which a bidding system may be used to determine the basis for the utility's avoided cost).
9. Reverse-the-meter approaches (in which energy produced is sent to the utility and reverses the meter that registers energy consumption so that the meter records the net energy consumed once QF production is taken into account).
10. Differential revenue requirements approaches (whereby the difference in a utility's revenue requirements are calculated with and without the QF purchase), usually through the use of detailed production cost or market simulation models.

In addition, in some jurisdictions, resources are developed and selected by utilities as a result of competitive RFP and resource solicitation processes. In cases where the process is administered with safeguards that prevent self-dealing or preferential treatment for resources being developed by the subject utility (e.g., the use of an independent evaluator or the adoption or presence of rules precluding offers from the host utility), bid prices submitted through the RFP process may be deemed as representative of the utility's avoided cost and in compliance with PURPA.

Q. HOW HAS THE MONTANA PSC RECENTLY ESTABLISHED AVOIDED COSTS?

A. In 1981, the Montana Legislature enacted "mini-PURPA," which also entitles QFs to sell electricity to electric utilities regulated by the Montana Public Service Commission ("PSC"). The Montana PSC has issued a number of avoided cost rulings in the period since PURPA was enacted. The Montana PSC also adopted FERC's avoided cost and QF rules by reference. The Montana rules require utilities to offer standard rates to QFs, but limit availability of long-term standard rates to QFs no larger than 3 megawatts ("MW"). QFs larger than 3 MW must negotiate agreements with QFs under the revised A.R.M. § 38.5.1902(5), adopted by the Montana Secretary of State on December 24, 2015.

In establishing an avoided cost methodology in Montana, the PSC has in the past utilized a proxy unit method, where avoided costs were established based on the cost of planned coal-fired generators. As NWE's resource plans, and the industry evolved, the proxy unit method transitioned to use the cost of a planned natural gas-fueled combined-cycle resource in establishing NWE's avoided cost. The last time that the PSC used Colstrip 4 as the basis for avoided cost, values were set at $99.41/MWh On-Peak, and $51.15/MWh Off-Peak. As the PSC transitioned to use of a NGCC unit in its proxy approach, it established Schedule QF-1 avoided cost rates of $90.87/MWh On-Peak and $54.44/MWh Off-Peak. The PSC again revisited avoided cost rates in 2014, in reviewing changes to avoided cost determination proposed by NWE. In that case, the PSC found:

> The Commission finds that the basic methodology used to calculate Option 1 rates has not fundamentally changed since 2010. In the last two QF-1 proceedings, the Commission estimated NWE's avoided cost by blending projected near-term market prices and the expected cost of owning and operating a natural gas CCCT.

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In the 2014 QF-1 proceeding, the PSC also identified concerns it had with NWE's avoided cost methodology. For example, the PSC noted that NWE had concluded just a few months earlier that the acquisition of the 439 MW of existing hydro assets was its least cost resource option, but continued to use a NGCC in its resource plan for estimating avoided cost. The PSC expressed concern that NWE had not provided adequate record evidence to support its avoided cost method and specific projections. The PSC expressed additional concern that a factual basis for differences between NWE QF-1 and QF-2 rates had also not been clearly articulated, and that NWE's proposal for establishing wind integration adjustments to avoided costs was not adequately supported by evidence. Given the evidentiary deficiencies it found in the proceeding, the PSC denied NWE's application, and ruled that previous avoided cost rates,

determined less than a year and a half previously at that point in time, remained valid and appropriate. This decision was recently upheld by a district court judge in Montana.

Q. WHAT IS THE CURRENT QF-1 RATE?

A. Table 1 lists NWE's current Schedule QF-1 avoided costs for long-term wind purchases:[1]

Table 1 – NWE Energy Standard Offer Schedule QF-1 Avoided Cost Rates

Option 1(c)	**Option 1 adjustments & conditions**
Duration: 19 months - 25 years	• Contingency reserves - QF opts to self-supply or purchase from NWE. Purchase rate based on CU4 reserve cost applied to QF technology • RECs - non CO2-emitting QFs may retain or convey RECs to NWE. If QF conveys RECs to NWE, rates are adjusted to reflect future CO2 emissions costs NWE incurs for CU4. • Wind integration - QF opts to self-supply or purchase integration service from NWE. Purchase rate is annually adjusted based on actual cost
Rate:	$0.05850 per kWh (On-Peak) $0.05314 per kWh (Off-Peak)
Option 2(a)	**Option 2 adjustments & conditions**
Duration: Up to 25 years	• Contingency reserves - QF opts to self-supply or purchase from NEW. • RECs - QFs retain RECs • Wind integration - QF opts to self-supply or purchase integration service from NWE. Purchase rate is in accordance with Wind Integration Tariff W1-1. • Contingency Reserves – QF opts to self-supply or purchase Contingency Reserves according to the Contingency Reserves Tariff CR-1.
Rate:	Highest-cost 25 MWh Mid-C purchase each hour less $1.00/MWh
Option 2(b)	**Option 2 adjustments & conditions**
Duration: Up to 25 years	• Contingency reserves - QF opts to self-supply or purchase from NEW. • RECs - QFs retain RECs • Wind integration - QF opts to self-supply or purchase integration service from NWE. Purchase rate is in accordance with Wind Integration Tariff W1-1. • Contingency Reserves – QF opts to self-supply or purchase Contingency Reserves according to the Contingency Reserves Tariff CR-1.

[1] The PSC suspended the availability of Option 1(a) rates for solar QFs in June 2016.

Rate:	ICE Mid-C index price in on/off peak periods less $1.00/MWh

The Option 2 tariffs listed above include Wind Integration charges using NWE's W1-1 tariff.

The Contingency Reserve CR-1 tariff rate is $10.10/MWh, and appears to apply to 3 percent of hourly integrated generation, and 3 percent of load served by that generation, for a total of 6%, or $0.606/MWh.

Q. WHAT WAS THE COMMISSION'S MOST RECENT AVOIDED COST DECISION?

A. In the recent avoided cost proceeding for the Greycliff project, in Docket 2015.8.64, I presented testimony discussing the Northwest Planning and Conservation Council (NPCC) 7th Power Plan Forecast. As the Commission is aware, adoption of that forecast as an avoided cost measure suggested an avoided cost of $53.39/MWh, based on the draft forecast values available at the time my testimony was prepared, or $48.32/MWh based on the final draft of the forecast.

In the Greycliff case, the Commission ultimately adopted an avoided cost of $45.49/MWh. This value reflected an avoided energy cost of $49.92/MWh which was the Commission's estimate of the levelized Mid-C market value. The avoided cost decision also included a Mid-C to Montana basis adjustment of -$4.56/MWh, a wind integration adjustment of -$1.84/MWh, and a capacity price adjustment of $1.98/MWh.

The avoided cost adopted by the Commission in Greycliff was approximately $10/MWh higher than the value proposed by NorthWestern. In terms of avoided cost methodology, the Commission adopted NorthWestern's proposed approach of using Mid-C forward price strips, and escalating energy prices from those price strips using the annual escalation rate for Henry Hub natural gas prices, as published in the U.S. Department of Energy, 2015 Annual Energy

Outlook. The Commission reduced avoided cost to reflect NorthWestern's Mid-C to Montana basis adjustment and wind integration charges, and increased it to reflect capacity value.

In the Greycliff case, NorthWestern proposed additional deductions to avoided cost that were rejected by the Commission. The Commission also rejected NorthWestern's PowerSimm modeling approach, of calculating a net long and short position in the energy market, and reducing avoided cost below forecast market prices, in cases where NorthWestern was long on energy.

Q. HAVE YOUR REVIEWED NORTHWESTERN'S APPLICATION AND SUPPORTING TESTIMONY, AND ITS PROPOSAL TO CHANGE THE QF-1 TARIFFS?

A. Yes. In its application and supporting testimony, NorthWestern states that its existing QF-1 tariffs are "significantly out of touch with current market reality." While it is true that near-term and recent natural gas and power prices have declined since 2014, it is not clear that the long-term expectation of natural gas and power prices has declined, especially not to the same extent implied by NorthWestern's testimony.

For example, as indicated above, the Commission recently approved a long-run avoided cost for Greycliff of $45.49, including adjustments. The energy component of that rate was $49.92/MWh. Adoption of the NPCC 7th Annual Plan electricity price forecast would result in a similar avoided energy cost. Those values are around 12 to 13 percent lower than the existing QF-1, Option 1 (c) tariff.

In contrast, NorthWestern is proposing revised energy avoided cost rates of $39.43 for wind resources, $39.88 for solar resources, and $37.76 for Hydro/Other resources, with carbon reduction benefits included. Those values are substantially lower than the avoided cost energy rate approved in Greycliff, and are 30 percent lower than the current QF-1 tariff. This large

discrepancy is driven by several aspects of NorthWestern's analysis, that tend to underestimate its actual avoided cost, and that if adopted, would subsidize NorthWestern ratepayers and shareholders, at the expense of QF-1 resources.

In following responses, I address some of the concerns I have with NorthWestern's avoided cost methodology.

Q. WHAT IS THE METHODOLOGY REPORTEDLY EMPLOYED BY NORTHWESTERN TO PRODUCE ITS AVOIDED COST ESTIMATE FOR QF-1 RESOURCES?

A. I base my understanding of NWE's approach to calculating an avoided cost for QF-1 Resources on the description of the approach as outlined in filed by Witnesses Bushnell and Hanson.

Mr. Hansen describes NorthWestern's approach where it completed a power system simulation using the PowerSimm model, for each of the QF-1 technology types. NorthWestern states that it simulated operation of its power system with and without inclusion of the QF-1 resources. As described, in assigning avoided cost value to QF energy production, NorthWestern differentiated between time periods when its system energy balance was in surplus or deficit. As described by Witness Hanson, the following differentiation was applied:

- For periods when the QF resource produces and delivers energy when NWE's supply portfolio is short (i.e., when generation is less than load), QF energy production is assigned the market purchase price for electricity that NWE would otherwise have purchased.
- For periods when the project produces and delivers energy when NWE's supply portfolio is long (i.e., when generation is greater than load) and the market price is higher than the variable cost of "avoidable resource", QF energy production is assigned the variable cost of avoidable resource. NWE states that this approach is appropriate, because in its view, the avoidable resource would be backed down, or reduce output to account for the QF production. NWE calls this position "Long-1."
- For periods when the QF project produces and delivers energy when NWE's supply portfolio is long and the market price is lower than the variable cost of the "avoidable resource," QF energy production receives a price of zero. NWE calls this position "Long-2."

NorthWestern uses this approach, and its related PowerSimm modeling, to estimate hours when its system is short, or in the Long-1 or Long-2 condition, based on QF energy production, and based on PowerSimm dispatch modeling of its loads and other generation assets.

NorthWestern assigns avoided cost value for each hour, based on the short and long conditions, and states that it examines the difference between simulations with and without the QF Resource. NorthWestern aggregates the hourly values applied to energy production from the QF facility, and spreads that over annual energy production, to derive avoided energy cost values.

NorthWestern's PowerSimm model relies upon externally produced forecasts of fuel prices, including natural gas prices, forecasts of electricity demand on the NWE system, and forecasts of available generating capacity and operating characteristics for NWE power plants. Most importantly, the model also relies upon an externally produced forecast of electricity prices. In its testimony and analysis, NWE provides only a cursory description of its approach, including the PowerSimm modeling, so the inner workings of the model are not at all transparent. This aspect critically limits the ability to analyze NWE's avoided cost methodology, and its specific projections for the QF-1 resources.

Q. WHAT CONCERNS, IF ANY, DO YOU HAVE OF THE METHODOLOGY EMPLOYED BY NWE TO CREATE AN AVOIDED COST ESTIMATE FOR THE QF-1 RESOURCES?

A. Under NWE's avoided cost approach, while the utility states that it conducted QF-In/QF-Out simulations, I understand that it did not use the PowerSimm model to actually measure changes in production cost with and without the QF-1 projects. In contrast, consistent with its approach in Greycliff, NorthWestern apparently completed PowerSimm simulations with and

without the QF resources, and used that information to tabulate whether it is in a net purchase or a net sales position. Then NWE took the additional step, external to the simulation, of applying a combination of forecast monthly energy prices, production cost estimates for "avoidable resources," or a value of zero, to the monthly forecast production of the QF-1 resources. NWE limited its use of the PowerSimm model only to estimate whether its system would be in a net purchase or net sale position, on a monthly basis, segmented by High Load (On-Peak) and Low Load (Off-Peak) periods.

NorthWestern's approach in not examining changes in production costs on its system, and in assigning the operating cost of an "avoidable resource", or zero, when the utility is in long energy position, violates industry best practice in estimating avoided cost. This approach is inconsistent with how NorthWestern actually operates its system, and is designed to subsidize NorthWestern shareholders and ratepayers, at the expense of QF resource owners and developers. A *less* punitive (to QFs) variant of this approach was rejected by the Commission in the Greycliff case, and should again be rejected by the Commission in setting QF-1 avoided cost rates.

Q. IS NORTHWESTERN'S AVOIDED COST APPROACH CONSISTENT WITH ECONOMIC DISPATCH PRINCIPLES?

A. No. In assigning the production cost of an avoidable resource to QF output under Long-1 conditions, NorthWestern is essentially assuming it will back down generation from its other resources, even when those resources are in the money, as is explained in more detail below. In actual operating scenarios where NorthWestern is in a net sales position and the market price of energy is higher than the variable operating cost of the avoidable resource (Long-1), NorthWestern will sell excess energy into the wholesale market. The QF resource should properly be credited with the market price as avoided cost value in that situation.

The approach taken here by NWE violates economic dispatch principles, and artificially suppresses estimated avoided cost. If the avoidable resource is "in the money," meaning its production costs are lower than the market price of energy, then there is no need to reduce its output during times when the QF resource is generating. The QF resource's dispatch cost will be zero, as the energy is taken whenever produced. Both resources will be in the money under this type of circumstance, so the prudent decision by NWE would be to sell additional energy into the market.

NorthWestern's approach of assigning a zero value to energy produced when in a Long-2 position is even more punitive to QFs. This goes a step further than the approach NorthWestern took in the Greycliff case, and should be rejected by the Commission. As NorthWestern is able to re-sell excess energy at the market price, that is the appropriate value to assign to QF energy production under the Long-2 condition.

Adopting the approach being used by NorthWestern is unduly discriminatory, and should be rejected by the Commission, just as it has done in its Greycliff decision.

Q. HAVE YOU SEEN DATA SUGGESTING THAT NORTHWESTERN IS ACTIVE IN BOTH PURCHASING AND SELLING ENERGY IN THE WHOLESALE MARKET?

A. Yes. NorthWestern consistently purchases and sells energy in the wholesale power market, both in its Montana operations and in its South Dakota operations. Table 2 below shows NorthWestern's market purchase and sale history, as reported through the FERC Form 1. These data were extracted by PMRG from the Energy Velocity datasource. As shown, NorthWestern routinely and consistently engages in both power sales and purchase activity in the wholesale power market.

Table 2 – NorthWestern Energy Purchase and Sales Data

	2010	2011	2012	2013	2014	2015
Power Purchases (MWh)	6,790,265	5,936,248	5,971,881	6,762,934	7,013,369	4,752,672
Energy Charges ($)	$299,843,946	$255,317,849	$252,484,353	$311,119,417	$304,822,900	$231,825,119
Demand Charges ($)	$19,457,729	$9,899,498	$12,917,081	$10,441,580	$11,166,832	$12,527,973
Total Charges ($)	$319,262,816	$265,180,449	$265,206,353	$321,523,916	$315,957,355	$244,320,023
Energy Charges ($/MWh)	$44.16	$43.01	$42.28	$46.00	$43.46	$48.78
Total Charges ($/MWh)	$47.02	$44.67	$44.41	$47.54	$45.05	$51.41
Power Sales (MWh)	2,446,738	1,398,453	1,429,602	1,965,449	2,425,078	3,522,568
Energy Sales Revenue ($)	$91,021,282	$22,387,196	$22,778,986	$47,864,234	$65,512,720	$84,836,564
Demand Revenue ($)	$0	$0	$0	$0	$0	$0
Total Energy Sales Revenue ($)	$91,021,282	$22,387,196	$22,778,986	$47,864,234	$65,512,720	$84,836,564
Energy Sales Revenue ($/MWh)	$37.20	$16.01	$15.93	$24.35	$27.01	$24.08
Total Sales Revenue ($/MWh)	$37.20	$16.01	$15.93	$24.35	$27.01	$24.08

Q. WHAT IS THE IMPACT ON AVOIDED COST OF NORTHWESTERN'S APPLICATION OF ITS NET LONG AND NET SHORT ANALYSIS JUST DESCRIBED?

A. In the PSC-013 Data Request, the Commission asked NorthWestern to calculate avoided costs using market sale price as the value of production under all long conditions, and market purchase price when short. When the market price is properly assigned as the avoided cost value, NorthWestern's avoided energy cost estimate increases by $5 to $6 per MWh. According to its response to PSC-013, the avoided energy cost for wind is $45.62/MWh, for solar is $45.02/MWh, and for Hydro/Other is $43.77/MWh.

Q. WHAT OTHER ISSUES HAVE YOU IDENTIFIED, IF ANY, REGARDING NWE'S AVOIDED COST METHODOLOGY IN THIS PROCEEDING?

A. Another concern I have is that NWE's avoided cost methodology is not transparent and is difficult to assess. As described, NWE states that it uses a forward electricity and natural gas price strip, and building from those price strips, the PowerSimm model develops prices and simulates operation of its system. Mr. Hanson, in his testimony, refers to using the natural gas and power price forecasts developed for NorthWestern's 2015 Electricity Supply Resource Procurement Plan.

In reviewing the 2016 On-Peak value for Mid-C energy prices used by NorthWestern, it is 12% lower than actual Mid-C On-Peak reported prices for 2016 to date. Given that NorthWestern's energy price forecasting approach is designed to look at current market expectations, and to then escalate energy prices long-term using forecast natural gas price escalation, it is important to have an accurate starting off point.

PMRG also reviewed information available on the Ascend Analytics (Ascend) website. Ascend is the developer of the PowerSimm model. In data responses, and phone conversations, NWE revealed that Ascend had been involved in completing the PowerSimm simulations, and that output data from the simulations resides on computer servers in the Ascend offices. The Ascend website refers to use of stochastic modeling and a mean-reversion algorithm for PowerSimm, but also provides very little detail, and no characterization of how stochastic parameters are derived or used in the model.

In its testimony and data responses, NorthWestern does not discuss the stochastic nature of the PowerSimm model, and does not provide any information about the algorithms used, the specification of probability distributions and correlation and covariance statistics, or other key input data and algorithms that play a pivotal role in the PowerSimm simulation environment. This is critical information to omit, because the specification of volatility and correlation parameters plays a key role in influencing the dispatch results, and calculation of net long and short energy market positions.

Q. HAVE YOU REVIEWED THE MONTANA TO MID-C ENERGY PRICE DIFFERENTIAL USED BY NORTHWESTERN IN ITS ANALYSIS?

A. Yes. While Mr. Hansen suggests that NorthWestern must pay for transmission costs when purchasing at Mid-C, and that it receives discounted energy prices when it sells excess energy in Montana. However, no data is provided to justify this claim, and in my opinion, the

location adjustment is overstated. When NorthWestern purchases QF energy and is in a net short position, it is able to avoid at least a portion of the basic difference included in Mr. Hansen's analysis, because it does not have to pay for transmission that it otherwise would when purchasing at Mid-C, or from WECC locations other than Montana. Similar to the Greycliff case, Mr. Hansen did not disclose this location adjustment in his testimony, but did disclose it in response to Data Request PSC-011. Mr. Hansen states that NorthWestern applied a $4.33/MWh Mid-C to Montana adjustment to the market energy prices, plus 5% losses. In total, for a Mid-C energy price of $50/MWh, this adjustment would add to $6.83/MWh. That is a substantial adjustment, and significantly higher than the current $1/MWh location adjustment in the QF-1 Option 1(a) and Option 2(b) tariffs. In my opinion, based on price observations, and fundamental market simulation work I have completed, this adjustment used by NorthWestern is more than double the level that is typical when modeling Montana, and comparing forecast energy prices to those at Mid-C.

I would note that with the reversal of the PowerSimm net short analysis discussed above, and if the location differential is reduced to $3/MWh, the QF-1 avoided energy cost estimates derived by NorthWestern would be very close to the $49/MWh+ values adopted by the Commission in the Greycliff case.

Q. WHAT ALTERNATIVE FORECAST DO YOU PROPOSE TO UTILIZE IN THIS PROCEEDING IN ORDER TO DEVELOP AVOIDED COST RATES FOR GREYCLIFF?

A. While it declined this approach in the Greycliff case, I continue to recommend that the Commission utilize the NPCC's electric price forecast from its Seventh Power Plan in establishing avoided cost, because it is objective, rigorous, and transparent, and utilizes best industry practices. The NPCC is a well-respected organization in the Pacific Northwest, and one

of its goals is to develop independent and objective power plans and policy analysis for the region. NWE relied upon the NPCC forecast and analysis in some of its resource planning efforts. NPCC developed it Seventh Power Plan using rigorous analytic approaches, and a detailed set of fundamental analyses. Its forecast is also transparent, and utilizes industry best practice modeling techniques. NPCC uses the Aurora XMP fundamental simulation model to develop the electricity price forecast. The NPCC forecast reflects recent declines in natural gas prices, but also reflects the structural changes that the power industry is undergoing, and fundamentally reflects those changes in development of its natural gas and electricity price forecasts, and in its underlying resource plan for the Northwest region. The forecast is fundamentally derived, so it reflects changing supply and demand conditions, and changing market heat rates that are anticipated in the Western U.S. power markets, in response to evolving fuel markets, environmental compliance policies, and renewable resource expansion. Adoption of the NPCC forecast would establish avoided energy cost for QF-1 resources at $48.32/MWh.

Q. HAVE YOU REVIEWED THE CAPACITY CONTRIBUTION APPROACHES PROPOSED BY NORTHWESTERN IN THIS PROCEEDING?

A. Yes. The capacity contribution percentage, particularly for solar resources, is well below the level established for solar generation in other jurisdictions. Recent integrated resource plans or solar capacity studies from other utilities in the West, including several utilities that neighbor NWE, value solar PV capacity at 30% to 50% of its nameplate capacity, far above the 9.6% capacity credit that NWE proposes. The solar capacity values used by these other western utilities include 28 to 51 percent used by Idaho Power, 34 to 39 percent used by Pacificorp, and 40% used by Public Service Company of Colorado. NorthWestern is substantially understating this value for solar resources.

In addition, the exceedance approach proposed by NorthWestern appears to unfairly subsidize NorthWestern shareholders and ratepayers, again at the expense of QF project owners and developers. As an example, according to data responses filed by NorthWestern, the exceedance value for the Dave Gates Generating Station is lower than that for solar resources. Yet, NorthWestern fully recovers capital and fixed costs in rates for Dave Gates. This highlights an implicit subsidy of the approach, which should be carefully examined by the Commission before adopting such a method.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing has been served on this 14th day of October, 2016 upon the following by first class mail postage pre-paid:

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I hereby certify an original was e-filed, and six copies of the foregoing were hand-delivered to the following:

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