DEPARTMENT OF PUBLIC SERVICE REGULATION

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MONTANA

IN THE MATTER OF NorthWestern Energy's	)	REGULATORY DIVISION
Application for Approval of Avoided Cost Tariff	)	
Schedule QF-1	)	DOCKET NO. D2016.5.39

RESPONSES TO DATA REQUESTS PSC-028 THROUGH PSC-035 OF THE MONTANA PUBLIC SERVICE COMMISSION TO VOTE SOLAR AND MEIC

PSC-028 Regarding: Electronic Files Witness: Beach

Please provide Excel-readable files of all Exhibits, Figures, Tables, avoided cost calculations, and ancillary information, with all calculations traceable.

Response:

Please see the attached Excel files.

- Analysis of Montana PCAFs.xlsx
- MidC Forecast - final.xlsx
- REVISED Exhibit_(JBB-1) D2016.5.39.xlsx
- Solar Exceedance and Capacity Value – Top 10 percent QF peak period.xlsm
- Updated MT Gas Forecast.xlsx
- Henry Hub – Historical Monthly Average Prices
- SAM Model Input files for 2010 to 2013 and TMY (for 2014-2015) lat46.105_lon-112.875_2010.csv, lat46.105_lon-112.875_2011.csv, lat46.105_lon-112.875_2012.csv, lat46.105_lon-112.875_2013.csv, and lat46.105_lon-112.875_TMY.csv (for 2014 and 2015).
  The SAM model inputs were used with NWE's SAM settings.

NorthWestern asserts that it is basing its choice of an 85% exceedance level in part on the 90% availability factor of a frame CT. *Bushnell Prefiled Direct Testimony* 11:1-5. At 22:14-16 you refer to a NERC report, *Accommodating High Levels of Variable Generation*, which notes that many control area operators assess the capacity contribution of solar resources based on their average capacity factor over a set of on-peak hours.

a. Please compare the merits of using an exceedance, or probable minimum output method to establish capacity contribution versus using an average capacity, or probable output method.

b. Please confirm, or deny with explanation that the use of an 80 MW CT with 90% availability to establish capacity costs implicitly recognizes the exceedance method, in that the CT is expected to be available to provide at least 80 MW of output in 90% of the hours under consideration.

c. At 22:19-21 you state that the average capacity factor over NorthWestern's top 10% of on-peak load hours is about 51% of nameplate. Please confirm, or deny with explanation that applying this result to the table shown on p.11 of Bushnell's prefiled direct testimony indicates that an output of at least 1.5 MW is achieved in fewer than 8% of the hours under review, and that this implies the probability the facility will achieve at least 51% of nameplate output in similar future hours is less than 8%.

d. If the Commission determined that the exceedance method will be used to establish capacity contribution, what would be your proposed exceedance threshold?

e. At 26:5-7 you state that 60% of exceedance over the top 10% of on-peak hours provides an output equal to 39% of nameplate. Please provide Excel worksheets to support this calculation.

Response:

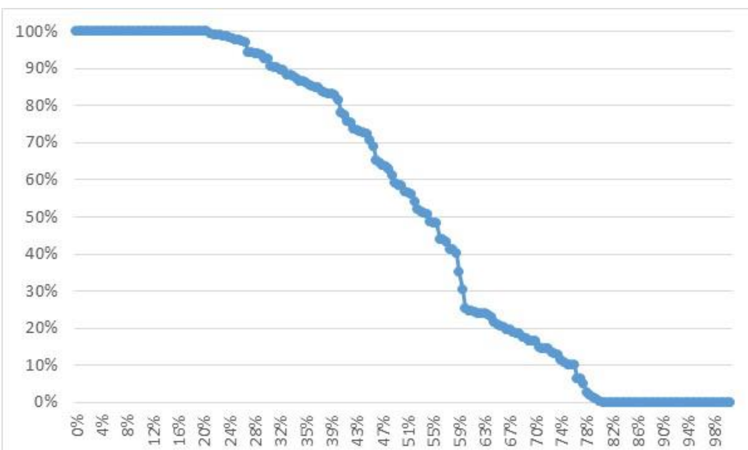
a. Average capacity (probable output) and exceedance (probable minimum) methods are both simplified approaches to evaluate the capacity value of variable resources. As the referenced NERC report concludes, these simplified approaches can be benchmarked to more rigorous evaluations of the capacity value of variable resources such as Effective Load Carrying Capability (ELCC) analyses. ELCC studies rely on reliability models to determine how much CT capacity must be installed in place of a given project (e.g. solar PV) or group of projects in order to achieve the same level of system reliability. System reliability is often measured using an annual measure of Loss of Load Expectation (LOLE). For example, if a system is assessed as having an LOLE of 10% (i.e. expect loss of load once every ten years), an ELCC study would determine how much CT capacity must be substituted for the solar resources in order to maintain an LOLE of 10%.

Generally, most of the control areas that have looked at this issue have chosen either the average capacity approach or relatively low exceedance values over a significant number of high-demand hours (such as the CAISO's 70% exceedance over 1,825 hours or SPP's 60% exceedance over 876 hours). For example, the California Public Utilities Commission (CPUC) staff performed an ELCC study of solar and wind resources in 2015 that found solar capacity values of over 50%, similar to the CAISO's 70% exceedance method.[1] Another example of an ELCC study that produced results similar to an average capacity factor approach is the Public Service of Colorado's 2013 distributed solar study.[2]

b. Deny. The capacity contribution of variable resources such as solar or wind must be measured statistically or stochastically, not based on requiring solar to achieve identical engineering performance as dispatchable fossil resources. The fact that an 80 MW CT is available 90% of the time does not say anything about how much CT capacity would be needed to achieve the same system reliability as a given amount of solar project capacity. This is what an ELCC study analyzes.

c. Deny. The figure (there is no table) on page 11 of Bushnell's prefiled direct testimony indicates that a 3 MW <u>wind</u> project operates above 111 kW 85% of the time during the top 10% of on peak load hours. This means that the 85% exceedance method would assign a 3.7% capacity factor (=111/3000) as the wind project's capacity value.

The comparable figure for a <u>solar</u> project looks very different, as shown below.



We developed this figure showing a <u>solar</u> project's generation duration curve during the top 10% of load hours in NWE's on-peak period, using data from 2014. 2014 is a single year in which the solar capacity value is similar to the 10-year average value of 51% used in Vote Solar's testimony. The figure shows that (1) the solar generation curve is convex (and not concave as for wind), and (2) an 85% exceedance would equal zero (i.e. solar generation in 2014 was zero in about 20% of the top 10% load hours in the on-peak period). The use of an 85% exceedance gives zero credit to the significant solar output in the majority of hours. For example, solar generation was at a 100% capacity factor in 20% of the hours. The next 60% of hours showed generation between 0% and 100%, for a 52.7% average across the entire period.

[1] Draft staff paper is at http://www.cpuc.ca.gov/workarea/downloadasset.aspx?id=6554.

[2] Appendix V of http://www.eei.org/issuesandpolicy/generation/NetMetering/Documents/Costs%20and%20Benefits%20of%20Distributed%20Solar%20Generation%20on%20the%20Public%20Service%20Company%20of%20Colorado%20System%20Xcel%20Energy.pdf.

A 50% capacity factor is exceeded 53.9% of the time. Thus, there does not appear to be a large difference between median (i.e. the capacity factor that is exceeded 50% of the time) and average (average capacity output across all hours) capacity factors for solar PV.

d. Assuming that the top 10% of on peak load hours are the hours used to analyze exceedance, a 50% (i.e. median) value would be similar to an average value. Moving to 60% would be more conservative, but would still be an acceptable middle-ground in comparison to the extreme 85% exceedance proposal by NorthWestern. Vote Solar would not propose an exceedance over 60% for the limited number of hours in the top 10% of NWE's on-peak hours.

e. See the revised version of the solar exceedance analysis: "**Solar Exceedance and Capacity Value – 60% exceed scenario.xlsx**." In this worksheet, the revision we made to our original solar exceedance workpaper was to set the exceedance "solve for" percentages (in column BH) to 60% (within rounding) by entering input exceedance values (in column BE) each year. 2009 was an exception, since the "solve for" exceedance was at 54% even with 0 MW input exceedance value. Note that input numbers higher than zero reduce the solved for exceedance from its initial value.

PSC-030 Regarding: Valuing QF-1 Power under Long Conditions Witness: Beach

a. Please confirm, or deny with explanation that pricing QF power at zero during forecasted Long-2 conditions is logically equivalent to curtailing without compensation under Long-2 conditions.

b. Please confirm, or deny with explanation that NorthWestern is obliged to preserve consumer indifference with respect to the procurement of QF power, or power from any other source, including its owned or proposed resources.

c. Please confirm, or deny with explanation, that NorthWestern customers are indifferent between these choices: 1) Purchasing QF power at market price for immediate sale at market price (assuming zero transaction costs); or 2) No purchase of QF power.

d. Please confirm, or deny with explanation, that NorthWestern customers are not indifferent between these choices: 1) Purchasing QF power at market price for immediate sale at market price (assuming non-zero transaction costs); or 2) No purchase of QF power.

Response:

a. Deny. That might be the case if market prices were zero in Long-2 conditions, but that is very unlikely. As explained in Mr. Beach's testimony, Long-2 conditions occur when market prices are below the marginal cost of dispatching the utility's own resources. That means the utility has an opportunity to save money for ratepayers by displacing its own marginal, higher-cost resources with either market purchases or with QF power priced at the market. In these circumstances, the utility's marginal cost should consider a larger pool of resources than just the utilities' own generation. If the utility is operating "out of merit order" with higher cost resources dispatched before lower cost resources or market purchases, marginal cost does not necessarily equal zero. Pricing QF power at zero during Long-2 conditions is not equivalent to curtailment because QF power may have value (avoiding market prices at non-zero prices, or avoiding higher cost internal generation).

b. Confirm. PURPA allows QFs to sell power to a utility at the utility's avoided cost, which is the utility's incremental cost of energy or capacity which, but for the QF purchase, the utility would have to generate or purchase from another source. Thus, avoided cost is defined in terms of preserving customer indifference to the procurement of QF supply.

c. Deny. The fundamental premise of PURPA is that it is beneficial to produce power at avoided cost prices from renewable or cogeneration QF resources, because such resources increase the energy independence and freedom of U.S. energy consumers. Therefore, even if these two options have the same economic impact on ratepayers, ratepayers will prefer purchasing QF power at market price for immediate sale at market price in order to advance the broader benefits of PURPA generation. Please also note that not purchasing from the QF may have the effect of suppressing supply that could lower market clearing prices and that canprovide a hedge against volatile fossil fuel prices.

d. Confirm. Option 1 is preferable, for the reasons explained in part c. above.

PSC-031 Valuing QF-1 Power under Long Conditions Witness: Beach

a. Please confirm, or deny with explanation that NorthWestern customers incur brokering costs and market price risk associated with buying and selling QF power under long conditions.

b. Please confirm, or deny with explanation that Vote Solar/MEIC would support the pricing of QF-1 power under long conditions at projected market prices, less a deduction representing the fair value of, at least, NorthWestern's power brokering services and market price risk.

c. If confirmed at (b), please provide and support an estimate of a reasonable deduction to market to compensate NorthWestern customers for expected cost and risk.

Response:

a. Deny. NorthWestern customers will incur administrative and transaction costs associated with the utility's activities buying and selling power in the wholesale market, even if there is no QF generation on its system. Vote Solar expects that incremental brokering costs (either buying or selling) will be just a small fraction of these expenses. Buying QF power will reduce the utility's market purchases in some hours, and may increase the utility's sales in other hours. Assuming that there is a small incremental brokering cost for additional market activity of any kind (either buying or selling), one would expect that the incremental brokering savings for hours with fewer market purchases due to QF power would offset the higher incremental brokering costs in those hours with increased sales as a result of QF purchases. Since NWE is generally short on resources (i.e. is a net buyer), one would expect that, overall, QF power would result in reduced brokering costs. Such minor changes in administrative costs generally are not included in avoided costs for QFs.

Market price risk is a general term that needs a more precise definition. If it is meant to refer to the risk that actual avoided market prices may be different than the expected market prices that were the basis of avoided cost calculations, it is true there are risks that actual avoided costs may fluctuate compared to estimates. However, there are rewards as well as risks associated with such fluctuations (e.g. actual market prices could either be higher or lower than expected). Under long conditions, where the utility has too much supply, if market prices are higher than expected, ratepayers will benefit from the sale of lower-cost QF generation into the market. In hours where the utility is short and must buy higher-priced market power, lower-cost QF generation can reduce the amount of high-priced market power that must be purchased. This is how QF generation can provide a valuable hedge for ratepayers against high market prices. For this reason, fixed-price QF power provides an overall market benefit, not a market risk.

b. Deny. Vote Solar/MEIC would support the pricing of QF-1 power under long conditions at projected market prices. However, there is no reason to add incremental costs for brokering and market price risk, for the reasons stated in response to part (a) above. If anything, adding QF power will avoid costs for brokering and market price risk.

c. N/A

PSC-032 Regarding: Avoided Transmission Capacity Costs Witness: Beach

Please provide Excel worksheets supporting your calculation of avoided transmission capacity costs equal to 49% of nameplate at 36:7-8.

Response:

Please refer to the Excel workpaper “Analysis of Montana PCAFs.xlsx”.

Please describe the Vote Solar/MEIC position on annual updates to QF-1 Tariff rates based upon changes in price indices and other factors in the approved avoided cost calculation.

Response:

Vote Solar supports annual updates to certain market price forecasts that are used in avoided cost pricing in Montana, in order to make NWE's avoided cost rates as accurate as possible. Periodic updates in these forecasts to reflect changed market conditions will increase the confidence of all stakeholders that long-term, 25-year avoided cost rates are being set fairly. Updated avoided cost rates based on these new market price forecasts should only apply prospectively, to contracts with new QFs executed after the new rates receive Commission approval and take effect.

Vote Solar strongly recommends that any updates to avoided cost rates use transparent market price data and a Commission-approved updating methodology. For example, expected market prices for natural gas and wholesale power are two significant factors in setting NWE's avoided costs under the current Blended Market + Combined Cycle method. The Commission could adopt an annual update to avoided cost rates based on two updated market price forecasts: (1) a revised long-term forecast for burner-tip natural gas prices based on the method that the Commission adopted in Order 7199e[3] and (2) a revised near-term forecast of Mid-C market prices for the years prior to the first year of operation for the avoided resource, based on an updated Mid-C forward curve.

Vote Solar would support such annual updates only in conjunction with the transparent, easily understood, and readily reproducible Blended Market – Combined Cycle method.[4] More significant, and potentially controversial, changes to the avoided cost calculation that result from changes to the assumed avoided resource(s) should only occur in the context of a full contested-case proceeding following the Commission's biennial reviews of the utility's IRP, where the utility's next resource additions are planned, debated, and reviewed. Changes to the avoided cost methodology itself (such as NWE's proposal in this case to shift to the Peaker Method) should receive a full review in the context of a full contested-case proceeding following the biennial IRP.

[3] This approach uses two years of forward market prices for the AECO hub, escalated to future years based on the current Energy Information Administration's (EIA) *Annual Energy Outlook* forecast. To the AECO price Vote Solar would add the current tariffed cost of transportation in Alberta and Montana to move gas to power plants on NWE's system, escalated in future years based on the expected inflation rate.

[4] Avoided cost methodologies that use complex computer models to calculate avoided energy prices (such as NWE's proposed Peaker Method) are not good candidates for an annual updating process for those energy prices. Production cost models are sufficiently complex and opaque that they require more detailed scrutiny of the input assumptions and modeling methods.

PSC-034 Regarding: Levelized Costs Witness: Beach

Please describe the Vote Solar/MEIC position on the use of levelized costs to set standard rates in the QF-1 Tariff.

Response:

Long-term QF rates in Montana presently are levelized over the contract term at the utility's weighted average cost of capital. Given the reliability of solar QF output, Vote Solar does not believe that levelization significantly increases risks for ratepayers. Reasonable performance standards for solar QF contracts also will mitigate any risks from levelization.

In fact, there is a benefit to levelizing QF contract rates over the entire contract term. Levelization improves the ability of QF projects to obtain financing and strengthens the ability of projects to operate long-term, by matching revenues to typical financing terms.

If levelization is not continued in order to reduce ratepayer risk, it is essential that the Commission direct the utilities to provide a fixed, published schedule of monthly or annual prices for the full 25-year contract term.

PSC-035 Regarding: Exceedance Parameters Witness: Beach

At 23:7-24:3 you provide examples of varied exceedance parameters used by other entities to determine capacity contribution.

a. Please provide theoretical support, if available, to justify the choice of a 60% or 70% exceedance level rather than 85%.

b. Please provide theoretical guidance, if available, to assist in selecting the set of load hours to be observed.

Response:

a/b. See response to question PSC-029, above. In theory, the choice of both (1) the exceedance percentage and (2) the number of peak hours to which an exceedance approach should apply can be chosen to produce similar results to more complex ELCC studies of the capacity value of variable wind and solar resources. These choices also should draw upon the experience of other control areas with large amounts of wind and solar capacity which have operated those systems for many years under resource adequacy requirements for solar and wind that are based on certain exceedance metrics over specific peak hours. Such examples include the CAISO with its 70% exceedance method over 1,825 hours and SPP with its 60% exceedance metric over 876 hours. In theory, a control area such as NWE with a far smaller amount of solar generation than the CAISO, for example, should have a higher solar capacity value (and can use a lower exceedance percentage), all else equal, because solar's capacity value declines at high penetrations as the load net of solar shifts to later in the day.

CERTIFICATE OF SERVICE

I hereby certify that on the11th day of November, 2016, I served the foregoing by first-class mail, postage prepaid, and electronic mail on the following:

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