NorthWestern Energy®

Before The Public Service Commission
Of the State of Montana

DOCKET NO. D2016.5.39

Application for Approval of Avoided Cost Tariff Schedule QF-1

REBUTTAL TESTIMONY

December 2016

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2016.5.39
Avoided Cost Rate Filing
NorthWestern Energy

PREFILED REBUTTAL TESTIMONY

OF JOHN B. BUSHNELL

ON BEHALF OF NORTHWESTERN ENERGY

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Witness Information

Q. Please state your name and business address.

A. My name is John B. Bushnell. My business address is 208 North Montana Avenue, Suite 205 Helena, Montana.

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

A. I am NorthWestern Energy's ("NorthWestern") Manager of Energy Supply – Planning and Regulatory.

Q. Are you the same John Bushnell who submitted prefiled direct and supplemental testimony in this docket??

A. Yes.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. My testimony addresses certain issues raised in the Pre-filed Direct Testimony of R. Thomas Beach on behalf of Vote Solar and the Montana Environmental Information Center.

Rebuttal of R. Thomas Beach Testimony

Q. Please discuss the particular issues you are addressing in Mr. Beach's testimony.

A. I will address Mr. Beach's testimony on the following issues:

- Mr. Beach's comparison of NorthWestern's calculated solar capacity contribution to that of other western utilities;
- Mr. Beach's use of NorthWestern's Balancing Area ("BA") to portray NorthWestern as a summer peaking utility;
- The use of ten years of solar data versus four years of solar data;
- Mr. Beach's high capacity contributions for solar Qualifying Facilities ("QF"), and the implications of using Mr. Beach's method for wind QFs;
- Mr. Beach's portrayal of the Southwest Power Pool ("SPP") method for calculating capacity contribution for intermittent resources;
- Mr. Beach's discussion of Effective Load Carrying Capability, and
- Mr. Beach's calculation of avoided cost using an internal combustion engine as the proxy resource.

Solar PV Capacity Values of other Western Utilities

Q. At page 9, Mr. Beach claims that NorthWestern has substantially underestimated the capacity contribution that solar provides and, in Table 2, shows that other select western utilities value solar capacity “far above” the capacity credit proposed by NorthWestern. Do you agree with Mr. Beach that the utilities shown in Table 2 represent a fair comparison to NorthWestern?

A. No. Mr. Beach shows a capacity credit for four utilities in Table 2: Avista, Idaho Power, Public Service of Colorado, and PacifiCorp – East. Noteworthy points regarding this table are as follows:

- The table indicates that the Avista value is for “summer only.”
- Idaho Power is a summer peaking utility.
- PacifiCorp – East is a summer analysis.
- Public Service of Colorado is a summer peaking utility.

These summer peaking utilities should not be compared to NorthWestern. Table 1 below shows NorthWestern’s seasonal peak hour loads from 2002 through 2015. Every peak hour load above 1,200 megawatts (“MW”) occurs in winter.

Table 1. NorthWestern Energy - Peak Hour Loads

Year	Winter Peak (MW)	Summer Peak (MW)
2002	892	958
2003	954	1,078
2004	1,096	1,000
2005	1,096	1,026
2006	1,112	1,122
2007	1,100	1,177
2008	1,225	1,071
2009	1,219	1,059
2010	1,166	1,045
2011	1,139	1,091
2012	1,106	1,133
2013	1,272	1,162
2014	1,206	1,115
2015	1,069	1,146

NorthWestern is a winter peaking utility which experiences bimodal seasonal peaks.

Retail Load versus Balancing Area Load

Q. At page 24, line 24, Mr. Beach states, “the utility’s winter and summer peak-hour demands are similar.” Do you agree with that statement?

A. No. Table 1 above indicates that NorthWestern is a winter peaking utility.

Q. At page 24, lines 25-27, Mr. Beach states, “The utility’s peak-hour retail customer demand is higher in the winter, but its peak-hour transmission system demand in its balancing area is higher in the summer.” Do you agree with that statement?

A. Yes, I agree with the statement, but the reference to NorthWestern's BA is completely misleading. His comparison implies that the Montana Public Service Commission ("Commission") should consider the peak loads of the rural electric co-operatives and retail choice customers on its transmission system when calculating NorthWestern's avoided costs. The calculation of NorthWestern's avoided cost must be based upon its cost of serving its own retail load, not the cost of providing transmission service to the rural electric co-operatives and retail choice customers in its transmission BA.

Four Years of Data versus Ten Years of Data

Q. At page 24, line 7, Mr. Beach states that NorthWestern only used four years of data to determine its proposed 9.6% solar photovoltaic ("PV") capacity value. What was the source of the 9.6%, cited by Mr. Beach, and how was it calculated?

A. The 9.6% capacity contribution for solar is based upon an 85% exceedance standard using 10% of On-Peak hours, and the calculation was provided in my response to Data Request PSC-017d in the "PSC-017d Solar" Excel file provided on CD. Table 2 below shows how the 9.6% was derived from four years of data.

Table 2. Exceedance Analysis for Solar	
Year	Capacity Contribution
2006	18.49%
2007	19.75%
2008	0.00%
2009	0.00%
Ave:	9.56%

Q. Why did you use four years of data?

A. I used four years of data because that was the data that I could readily access at the time I prepared my testimony. I agree that using ten years of data would provide a better indication of capacity contribution than just using four.

Q. Have you updated your analysis using ten years of data?

A. Yes. In response to Data Request NWE-001, Mr. Beach provided an Excel spreadsheet showing his calculations, using ten years of data. I used that data to update my analysis. Consistent with my earlier calculations, I used the top 10% of On-Peak load data and calculated a ten-year average 85% exceedance value. The solar PV capacity contribution is 3.4%, which is obviously lower than the 9.6% I calculated using only four years of data.

Q. Why did using ten years of data result in a lower calculated capacity contribution?

A. While my original analysis used only four years of data, it included two years in which summer On-Peak loads dominated the analysis and two years in which winter On-Peak loads dominated the analysis. Expanding the analysis to ten years added only one more year of data dominated by summer On-Peak loads, but added four more years of data dominated by winter On-Peak loads. Thus, the average capacity contribution of solar PV resources was lower in the ten year analysis.

Q. But doesn't the current QF-1 Tariff currently pay solar QFs their average production for 100% of On-Peak Hours?

A. Yes, it does, and that is part of the problem with the current tariff. In the D2012.1.3 QF-1 docket, I had originally proposed to tariff all intermittent resources based upon a 5% capacity contribution. However, at that time, NorthWestern knew very little about the production characteristics of solar resources, and in rebuttal testimony re-grouped solar resources in to the Option 1(a) tariff, which had the effect of giving solar QFs a 38% capacity contribution. This is the reason that the current tariff has an effective rate of over $66 per megawatt-hour ("MWh").

Beach – Solar Capacity Contribution

Q. At page 23, Mr. Beach includes Table 6, showing a range of solar capacity values. What is your understanding of the values shown in this table?

A. It is my understanding that this table shows the following four methods of calculating solar capacity contribution:

- The capacity factor over 100% of On-Peak hours;
- The capacity factor over the top 10% of On-Peak hours;
- 60% exceedance method over the top 10% of On-peak hours, and
- 85% exceedance method over the top 10% of On-peak hours.

It is my understanding that Mr. Beach is proposing that the Commission adopt the "Capacity factor over 100% of On-Peak hours" method. Under this method, the average generation output of the solar project over all On-Peak hours is equal to the capacity contribution in any one year, and the average over ten years is equal to the 38% capacity contribution for solar QFs.

Q. Is Mr. Beach's proposal reasonable?

A. No, it is not. Using 100% of On-Peak hours would mean using roughly 2,038 hours per year out of 8,760, or roughly a quarter of all hours. Using all On-Peak hours diminishes the value of the analysis. Moreover, Mr. Beach's proposal to use the average production for solar PV as the capacity contribution has no bearing on the reliable level of generation that NorthWestern is able to count on from these resources at times of highest peak load.

Capacity Contribution of Wind – Using the Beach Method

Q. Has Mr. Beach proposed using any of these methods for wind QFs?

A. No.

Q. What would Mr. Beach's table show if it were reproduced using ten years of wind data?

A. Table 3 below shows the results of Mr. Beach's methods using ten years of wind data. The data includes all wind resources, larger than 9-MW nameplate, in NorthWestern's resource portfolio from 2006 through 2015. The first method, Mr. Beach's proposed method for solar QFs, shows that wind QFs should receive a capacity contribution of 43.1%.

Table 3. Mr. Beach's Methods Applied to NorthWestern Wind

Method	Season(s)	Solar Capacity Value (% of nameplate)
Capacity factor over 100% of On-Peak hours	Summer and Winter	43.1%
Capacity factor over top 10% of On-Peak Hours	Summer and Winter	34.0%
	Summer only	18.6%
	Winter only	40.3%
60% exceedance over Top 10% of On-Peak hours	Summer and Winter	31.1%
85% exceedance over Top 10% of On-Peak hours	Summer and Winter	3.4%

Q. In your opinion, does Mr. Beach's method produce reasonable results?

A. Absolutely not. It is not reasonable to award capacity contribution to intermittent resources based upon their average energy production during peak load hours, and the Commission should reject Mr. Beach's proposal to do so.

<u>Capacity Contribution of Solar PV – Using SPP Method</u>

Q. At page 23, line 15 through page 24, line 3, Mr. Beach states that:

> **"The Southwest Power Pool (SPP) also uses an exceedance approach, but measured over 10% of all hours (i.e., 876 hours), not just over the top 10% of on-peak hours. SPP also uses ten years of data, and recently reduced its exceedance percentage for determining wind capacity values from 85% to 60%. As shown in Table 6 above, even using SPP's 60% exceedance over NWE's top 10% of on-peak hours (with ten years of data) results in a solar capacity value of 39%."**

Do you agree with Mr. Beach's analysis?

A. No, I do not. As a member of SPP in South Dakota, NorthWestern has followed SPP's development of its capacity contribution for intermittent resources. In October 2016, NorthWestern obtained SPP's Net Planning Capability ("NPC") calculation tool, which is an Excel workbook template for the calculation of the NPC value, or peaking capacity contribution. This methodology is based on using the top 3% of load hours for each month, and a 60% generation exceedance value for these hours in all of the annual peak months of the calculation period. This calculation is described in the SPP Planning Criteria (Version 1.0), section 7.1.5.3 (7), and has been provided with this testimony as Exhibit__(JBB-5). If actual generation data are not available for resources with less than three full calendar years of production, calculated or simulated generation data, based on wind or solar data (within certain restrictions), can be used. Prior to having three calendar years of data, the default NPC values are used (5% of nameplate for wind, 10% of nameplate for solar, as described in paragraph (7)(e)(iii) of the SPP Planning Criteria contained in Exhibit__(JBB-5).

This template was used to calculate the NPC for the three wind resources in NorthWestern's South Dakota portfolio. The resulting NPC values will be submitted to SPP as part of the 2017 reserve requirement planning process. Using that template, the ten years of solar data in this docket, and ten years of Montana load data, NorthWestern calculates a ten-year capacity credit for solar of 6.1%, not the 39% as calculated by Mr. Beach. A screenshot of the summary tab of the template showing the output of this calculation is included as Exhibit__(JBB-6). The summary tab shows an Annual Net Renewable Capability value of 0.2 MW, which is rounded up from the value of 0.160523 MW shown in the Formula Bar.

Q. Would you be opposed to using the SPP method for calculating the capacity contribution of intermittent resources?

A. No, I wouldn't be opposed to using the SPP capacity credit method in Montana.

Effective Load Carrying Capacity

Q. At page 26, Mr. Beach discusses Effective Load Carrying Capacity ("ELCC") analysis for determining capacity contribution. What are your recommendations regarding ELCC?

A. NorthWestern is committed to studying capacity contributions by resource type and intends to study ELCC and other methods of measuring capacity contribution in its 2017 resource planning process. However, NorthWestern shares Mr. Beach's concern that NorthWestern is so resource deficient that an ELCC analysis could be highly artificial. In the 2017 resource planning process, the ELCC method will be examined, along with other methods for determining capacity contribution.

Beach – Calculation of Avoided Costs

Q. At page 11, Mr. Beach describes the blended market combined cycle method adopted by the Commission in prior QF-1 proceedings as the simplest of the avoided cost methods. Do you agree?

A. Yes, I do agree. The blended market combined cycle method measures avoided cost using market purchases and a proxy energy resource that is usually, but not always, identified in NorthWestern resource plan. The simplicity of the blended market combined cycle method means that the calculation is relatively simple, but has significant limitations. The primary limitation is that the method calculates the same avoided cost for every

QF generation resource. Mr. Beach recognized this limitation when he proposed to award solar QFs 107% of the around-the-clock ("ATC") price. As pointed out in the Prefiled Rebuttal Testimony of Luke P. Hansen ("Hansen Rebuttal Testimony"), an hourly dispatch model, such as PowerSimm™, values the energy from each QF resource type based upon the hourly production profile of the resource; no after-the-fact adjustment is necessary.

Q. At page 15, Mr. Beach provides a table, (Table 4), showing the results of his avoided cost calculation using the "proxy" method. Have you examined Mr. Beach's avoided cost calculations?

A. I have examined Mr. Beach's avoided cost calculations, which are based upon my Exhibit__(JBB-1), which accompanied my prefiled direct testimony in this docket.

Q. For what purpose did you include Exhibit__(JBB-1) in your prefiled testimony?

A. Exhibit__(JBB-1) was provided with my prefiled testimony for the express purpose of showing the effect of changes in natural gas price forecasts, since the time that the current QF-1 Tariff was approved in August 2013. Except for changes in natural gas price forecasts, all assumptions and inputs in that analysis originated from NorthWestern's 2011 Electricity Supply Resource Procurement Plan.

Q. Is Mr. Beach's analysis, which uses Internal Combustion Engine ("ICE") units as the "proxy" resource, an appropriate application of the proxy method?

A. No, it is not. The proxy or committed unit method assumes that a QF will enable a utility to delay or avoid its next planned generation unit.[1] By using the ICE unit as the proxy resource, Mr. Beach assumes that solar QFs will enable NorthWestern to delay or avoided its planned ICE units. That assumption is not true.

Mr. Beach portrays solar QF generation as a capacity resource that will serve to delay or supplant NorthWestern's need for capacity resources. As I have shown in my previous testimony, NorthWestern is a winter peaking utility. I have also shown that solar QF resources do not provide any significant capacity contribution during peak load hours. Lastly, using the ICE unit as a proxy for avoided costs would compensate QFs for attributes that they are not capable of providing – attributes that only units under automatic generation control (AGC) are capable of providing. The Hansen Rebuttal Testimony and the Prefiled Rebuttal Testimonies of Michael R. Cashell and Bleau J. LaFave provide additional comments on Mr. Beach's calculation of avoided costs and "other benefits" provided by solar generation.

[1] Edison Electric Institute, *PURPA: Making the Sequel Better than the Original*, p. 9 (Dec. 2006).

<u>**Updated Avoided Capacity Costs**</u>

Q. In your prefiled direct testimony, you proposed that the avoided cost of capacity be calculated using the levelized capital cost of an ICE generation unit to be built in 2019. Is this the appropriate resource to measure avoided capacity?

A. No, it is not.

Q. If an ICE generation unit is not the appropriate unit to use for measuring avoided cost, why did you include the ICE in your prefiled testimony?

A. Although the ICE unit is not the appropriate unit to use in the calculation of avoided costs, it is the capacity resource selected in the 2015 Electricity Supply Resource Procurement Plan ("2015 Plan"). In the QF-1 proceeding in Docket D2014.1.5, the Commission rejected NorthWestern's filing for including a resource not included in its resource plan. I used an ICE in this filing to avoid the possibility that the Commission would reject this filing on similar grounds.

As stated in the 2015 Plan, NorthWestern selected ICE units at additional cost, because of the flexible operations they are capable of providing. No intermittent resource has the ability to provide the flexible operations that ICE units are capable of providing.

Q. What is the appropriate peaking unit that should be used to calculate avoided capacity costs?

A. The least cost capacity resource identified in the 2015 Plan is an Aeroderivative Combustion Turbine ("AERO") unit. This is NorthWestern's lowest cost option for a capacity resource when fixed capital and fixed operation and maintenance ("O&M") costs are considered.

Q. What is the avoided cost of capacity when calculated using the costs of an AERO unit?

A. The 25-year levelized capital cost of an AERO generation unit built in 2018 is $109.05/kilowatt-year ("kW-year"). The fixed O&M costs of AERO start at $6.42/kW-year in 2018 and escalate at 2% per year thereafter. The net present value of the annual stream of fixed costs are then levelized using NorthWestern's average weighted cost of capital (also from the 2015 Plan) resulting in a 25-year levelized avoided capacity cost of $116.73/kW-year. This calculation supersedes the calculations provided in Exhibit__(JBB-2), page 4 of 10 (which also contains cell reference errors) that accompanied my prefiled direct testimony. The updated exhibit is provided as page 4 of 10, in Exhibit__(JBB-4).

<u>Updated Avoided Cost Workpapers</u>

Q. Do you propose any changes to the default capacity contributions that you proposed for hydro, wind and solar resources in your prefiled direct testimony?

A. Yes, I do. In my prefiled direct testimony, I proposed default capacity contributions of 11.1% for hydro, 5% for wind, and 7.8% for solar QF resources. These default capacity contributions were used for rate comparisons and for the default capacity contribution under the second option for determining a five-year average measured capacity contribution. Updated analysis shows that I initially underestimated the capacity contribution of hydro and solar, which are shown in my response to Data Request PSC-017d to be 36.9% for hydro and 9.6% for solar.

Q. Have you updated your Exhibit__(JBB-2) to reflect the above change in avoided capacity costs and other changes introduced in the Hansen Rebuttal Testimony?

A. Yes. Exhibit__(JBB-4) is an updated set of workpapers, which reflect all of the proposed changes.

Q. Have you prepared an updated table showing the average calculated rates under the current QF-1 Tariff and under your rebuttal filed proposed rates?

A. Yes, I have. Table 4 below compares average calculated rates by resource type under current and proposed QF-1 rates (also shown on page 8 of Exhibit__(JBB-4)).

Table 4.

Average Annual Rates for 25-Year Contracts at Current Rates		
Resource Type	Without Carbon	With Carbon
Non-Wind [1]	$0.06235	NA
Wind [1]	$0.05439	NA
Non-Wind (Solar) [2]	$0.06609	NA

[1] Annual average rate

[2] Option 1(a) Rate - modeled production, page 9, Exhibit__(JBB-4)

Effective Average Annual Rates for 25-Year Contracts at Proposed Rates		
Resource Type	Without Carbon	With Carbon
Hydroelectric and Other QF [3]	$0.03445	$0.04559
Wind [4]	$0.02909	$0.04079
Solar [5]	$0.03276	$0.04398

[3] 57% annual capacity factor, 36.9% capacity contribution

[4] 38% annual capacity factor, 5% capacity contribution

[5] Modeled solar PV production, page 10, Exhibit__(JBB-4)

Q. How do the rates contained in Table 4 compare to those contained in your prefiled direct and supplemental testimonies?

A. Table 5 below shows the cumulative effect of the changes proposed from prefiled direct and supplemental testimony to rebuttal testimony.

Table 5. Changes from prefiled direct and prefiled supplemental to rebuttal

QF Resource Type	Prefiled		Rebuttal		Change	
	Without Carbon	With Carbon	Without Carbon	With Carbon	Without Carbon	With Carbon
Hydroelectric and Other QF	$0.03580	$0.04570	$0.03445	$0.04559	-3.77%	-0.24%
Wind	$0.03002	$0.04166	$0.02909	$0.04079	-3.09%	-2.08%
Solar	$0.03405	$0.04366	$0.03276	$0.04398	-3.78%	0.74%

Concluding Remarks

Q. Do you have any concluding remarks?

A. Yes. Mr. Beach's testimony suggests resource attributes to solar QF resources that might be applicable to summer peaking utilities, but are not applicable to NorthWestern. NorthWestern is not a summer peaking utility; it is a winter peaking utility that exhibits bimodal seasonal peaks, sometimes peaking in the summer, sometimes in the winter. Mr. Beach's recommendations represent a step backward in the calculation of avoided cost by individual resource type.

The Commission should reject Mr. Beach's testimony regarding solar capacity contribution, as well as Mr. Beach's calculation of avoided costs, which uses an ICE unit as NorthWestern's proxy resource. Instead, the Commission should adopt Mr. Hansen's proposed calculations of avoided energy costs by resource type, along with my proposed avoided cost of capacity and proposal to adopt measure-and-pay for capacity.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

INCLUDES AERO CT UNIT FOR CAPACITY
HAS NOT BEEN UPDATED FOR CURRENT MARKET PRICE FORECAST

Avoided Cost Energy Rates Without Transfer of Environmental Benefits

Length of Contract	Hydroelectric and Other QF	Wind QF	Solar QF
(years)	($/kWh)	($/kWh)	($/kWh)
1	$0.01700	$0.01790	$0.01880
2	$0.01731	$0.01824	$0.01920
3	$0.01812	$0.01906	$0.02017
4	$0.01843	$0.01941	$0.02054
5	$0.01878	$0.01975	$0.02090
6	$0.01935	$0.02032	$0.02158
7	$0.01978	$0.02075	$0.02200
8	$0.02040	$0.02145	$0.02259
9	$0.02085	$0.02197	$0.02300
10	$0.02127	$0.02246	$0.02338
11	$0.02169	$0.02293	$0.02378
12	$0.02214	$0.02340	$0.02425
13	$0.02255	$0.02382	$0.02466
14	$0.02292	$0.02421	$0.02505
15	$0.02328	$0.02459	$0.02542
16	$0.02360	$0.02492	$0.02575
17	$0.02391	$0.02524	$0.02605
18	$0.02419	$0.02554	$0.02634
19	$0.02447	$0.02583	$0.02661
20	$0.02473	$0.02610	$0.02687
21	$0.02497	$0.02636	$0.02711
22	$0.02521	$0.02661	$0.02735
23	$0.02544	$0.02686	$0.02759
24	$0.02567	$0.02711	$0.02782
25	$0.02589	$0.02734	$0.02805

Avoided Cost Energy Rates With Transfer of Environmental Benefits

Length of Contract	Hydroelectric and Other QF	Wind QF	Solar QF
(years)	($/kWh)	($/kWh)	($/kWh)
1	$0.01700	$0.01790	$0.01880
2	$0.01731	$0.01824	$0.01920
3	$0.01812	$0.01906	$0.02017
4	$0.01843	$0.01941	$0.02054
5	$0.02035	$0.02159	$0.02259
6	$0.02193	$0.02337	$0.02433
7	$0.02354	$0.02518	$0.02593
8	$0.02496	$0.02668	$0.02737
9	$0.02611	$0.02790	$0.02852
10	$0.02713	$0.02899	$0.02953
11	$0.02807	$0.02997	$0.03044
12	$0.02904	$0.03093	$0.03140
13	$0.02991	$0.03181	$0.03227
14	$0.03069	$0.03259	$0.03303
15	$0.03143	$0.03334	$0.03378
16	$0.03211	$0.03403	$0.03444
17	$0.03276	$0.03469	$0.03508
18	$0.03337	$0.03531	$0.03568
19	$0.03396	$0.03590	$0.03625
20	$0.03451	$0.03647	$0.03680
21	$0.03504	$0.03701	$0.03732
22	$0.03556	$0.03754	$0.03782
23	$0.03606	$0.03806	$0.03832
24	$0.03655	$0.03856	$0.03880
25	$0.03703	$0.03904	$0.03927

Avoided Cost Capacity Rates

Length of Contract	All QF Resources
(years)	($/kW-Year)
1	$115.46
2	$115.53
3	$115.59
4	$115.65
5	$115.71
6	$115.77
7	$115.83
8	$115.88
9	$115.94
10	$116.00
11	$116.05
12	$116.11
13	$116.16
14	$116.21
15	$116.26
16	$116.31
17	$116.36
18	$116.41
19	$116.46
20	$116.51
21	$116.55
22	$116.60
23	$116.64
24	$116.69
25	$116.73

Avoided Cost of Energy - Without Transfer of Environmental Benefits

Hydroelectric and Other QF Resources				Intermittent Wind				Intermittent Solar			
Year	Avoided Cost of Energy	Contract Length	Levelized Energy Rate By Contract Length	Year	Avoided Cost of Energy	Contract Length	Levelized Energy Rate By Contract Length	Year	Avoided Cost of Energy	Contract Length	Levelized Energy Rate By Contract Length
	($/kWh)	(years)	($/kWh)		($/kWh)	(years)	($/kWh)		($/kWh)	(years)	($/kWh)
2018	$0.01700	1	$0.01700	2018	$0.01790	1	$0.01790	2018	$0.01880	1	$0.01880
2019	$0.01763	2	$0.01731	2019	$0.01860	2	$0.01824	2019	$0.01964	2	$0.01920
2020	$0.01991	3	$0.01812	2020	$0.02088	3	$0.01906	2020	$0.02231	3	$0.02017
2021	$0.01950	4	$0.01843	2021	$0.02063	4	$0.01941	2021	$0.02180	4	$0.02054
2022	$0.02045	5	$0.01878	2022	$0.02137	5	$0.01975	2022	$0.02263	5	$0.02090
2023	$0.02288	6	$0.01935	2023	$0.02380	6	$0.02032	2023	$0.02578	6	$0.02158
2024	$0.02309	7	$0.01978	2024	$0.02406	7	$0.02075	2024	$0.02522	7	$0.02200
2025	$0.02608	8	$0.02040	2025	$0.02797	8	$0.02145	2025	$0.02798	8	$0.02259
2026	$0.02579	9	$0.02085	2026	$0.02769	9	$0.02197	2026	$0.02751	9	$0.02300
2027	$0.02671	10	$0.02127	2027	$0.02875	10	$0.02246	2027	$0.02833	10	$0.02338
2028	$0.02793	11	$0.02169	2028	$0.02989	11	$0.02293	2028	$0.02974	11	$0.02378
2029	$0.02972	12	$0.02214	2029	$0.03124	12	$0.02340	2029	$0.03207	12	$0.02425
2030	$0.03035	13	$0.02255	2030	$0.03196	13	$0.02382	2030	$0.03267	13	$0.02466
2031	$0.03102	14	$0.02292	2031	$0.03264	14	$0.02421	2031	$0.03336	14	$0.02505
2032	$0.03199	15	$0.02328	2032	$0.03364	15	$0.02459	2032	$0.03446	15	$0.02542
2033	$0.03232	16	$0.02360	2033	$0.03402	16	$0.02492	2033	$0.03461	16	$0.02575
2034	$0.03304	17	$0.02391	2034	$0.03484	17	$0.02524	2034	$0.03514	17	$0.02605
2035	$0.03355	18	$0.02419	2035	$0.03542	18	$0.02554	2035	$0.03566	18	$0.02634
2036	$0.03444	19	$0.02447	2036	$0.03634	19	$0.02583	2036	$0.03656	19	$0.02661
2037	$0.03513	20	$0.02473	2037	$0.03710	20	$0.02610	2037	$0.03734	20	$0.02687
2038	$0.03555	21	$0.02497	2038	$0.03762	21	$0.02636	2038	$0.03776	21	$0.02711
2039	$0.03678	22	$0.02521	2039	$0.03892	22	$0.02661	2039	$0.03895	22	$0.02735
2040	$0.03777	23	$0.02544	2040	$0.03988	23	$0.02686	2040	$0.04006	23	$0.02759
2041	$0.03890	24	$0.02567	2041	$0.04106	24	$0.02711	2041	$0.04115	24	$0.02782
2042	$0.03992	25	$0.02589	2042	$0.04219	25	$0.02734	2042	$0.04224	25	$0.02805

Avoided Cost of Energy - With Transfer of Environmental Benefits

Hydroelectric and Other QF Resources				Intermittent Wind				Intermittent Solar			
Year	Avoided Cost of Energy	Contract Length	Levelized Energy Rate By Contract Length	Year	Avoided Cost of Energy	Contract Length	Levelized Energy Rate By Contract Length	Year	Avoided Cost of Energy	Contract Length	Levelized Energy Rate By Contract Length
	($/kWh)	(years)	($/kWh)		($/kWh)	(years)	($/kWh)		($/kWh)	(years)	($/kWh)
2018	$0.01700	1	$0.01700	2018	$0.01790	1	$0.01790	2018	$0.01880	1	$0.01880
2019	$0.01763	2	$0.01731	2019	$0.01860	2	$0.01824	2019	$0.01964	2	$0.01920
2020	$0.01991	3	$0.01812	2020	$0.02088	3	$0.01906	2020	$0.02231	3	$0.02017
2021	$0.01950	4	$0.01843	2021	$0.02063	4	$0.01941	2021	$0.02180	4	$0.02054
2022	$0.02949	5	$0.02035	2022	$0.03193	5	$0.02159	2022	$0.03234	5	$0.02259
2023	$0.03163	6	$0.02193	2023	$0.03432	6	$0.02337	2023	$0.03506	6	$0.02433
2024	$0.03587	7	$0.02354	2024	$0.03903	7	$0.02518	2024	$0.03821	7	$0.02593
2025	$0.03814	8	$0.02496	2025	$0.04065	8	$0.02668	2025	$0.04069	8	$0.02737
2026	$0.03876	9	$0.02611	2026	$0.04132	9	$0.02790	2026	$0.04115	9	$0.02852
2027	$0.04027	10	$0.02713	2027	$0.04293	10	$0.02899	2027	$0.04251	10	$0.02953
2028	$0.04192	11	$0.02807	2028	$0.04452	11	$0.02997	2028	$0.04395	11	$0.03044
2029	$0.04545	12	$0.02904	2029	$0.04725	12	$0.03093	2029	$0.04763	12	$0.03140
2030	$0.04660	13	$0.02991	2030	$0.04854	13	$0.03181	2030	$0.04885	13	$0.03227
2031	$0.04748	14	$0.03069	2031	$0.04954	14	$0.03259	2031	$0.04949	14	$0.03303
2032	$0.04952	15	$0.03143	2032	$0.05149	15	$0.03334	2032	$0.05196	15	$0.03378
2033	$0.05042	16	$0.03211	2033	$0.05258	16	$0.03403	2033	$0.05232	16	$0.03444
2034	$0.05218	17	$0.03276	2034	$0.05435	17	$0.03469	2034	$0.05407	17	$0.03508
2035	$0.05360	18	$0.03337	2035	$0.05587	18	$0.03531	2035	$0.05544	18	$0.03568
2036	$0.05531	19	$0.03396	2036	$0.05764	19	$0.03590	2036	$0.05721	19	$0.03625
2037	$0.05687	20	$0.03451	2037	$0.05925	20	$0.03647	2037	$0.05880	20	$0.03680
2038	$0.05817	21	$0.03504	2038	$0.06059	21	$0.03701	2038	$0.06014	21	$0.03732
2039	$0.06056	22	$0.03556	2039	$0.06323	22	$0.03754	2039	$0.06233	22	$0.03782
2040	$0.06262	23	$0.03606	2040	$0.06518	23	$0.03806	2040	$0.06447	23	$0.03832
2041	$0.06464	24	$0.03655	2041	$0.06725	24	$0.03856	2041	$0.06637	24	$0.03880
2042	$0.06667	25	$0.03703	2042	$0.06939	25	$0.03904	2042	$0.06853	25	$0.03927

Avoided Cost of Capacity
Small AERO SCCT

Year	Annual Capital	Fixed O&M 2.0%	Avoided Capacity	Contract Length	Levelized Capacity By Contract Length
	($/kW-yr)	($/kW-yr)	($/kW-yr)	(years)	($/kW-yr)
2018	109.05	6.42	115.46	1	115.46
2019	109.05	6.55	115.59	2	115.53
2020	109.05	6.68	115.72	3	115.59
2021	109.05	6.81	115.86	4	115.65
2022	109.05	6.95	115.99	5	115.71
2023	109.05	7.08	116.13	6	115.77
2024	109.05	7.23	116.27	7	115.83
2025	109.05	7.37	116.42	8	115.88
2026	109.05	7.52	116.57	9	115.94
2027	109.05	7.67	116.72	10	116.00
2028	109.05	7.82	116.87	11	116.05
2029	109.05	7.98	117.03	12	116.11
2030	109.05	8.14	117.19	13	116.16
2031	109.05	8.30	117.35	14	116.21
2032	109.05	8.47	117.51	15	116.26
2033	109.05	8.64	117.68	16	116.31
2034	109.05	8.81	117.86	17	116.36
2035	109.05	8.99	118.03	18	116.41
2036	109.05	9.17	118.21	19	116.46
2037	109.05	9.35	118.40	20	116.51
2038	109.05	9.54	118.58	21	116.55
2039	109.05	9.73	118.77	22	116.60
2040	109.05	9.92	118.97	23	116.64
2041	109.05	10.12	119.17	24	116.69
2042	109.05	10.32	119.37	25	116.73

NorthWestern Energy 2015 Resource Procurement Plan
Resource Cost Summary
(2015$)

Resource Description	Fuel Source	Technology	Net Capacity (MW)	Cold Startup Cost $	Capital Cost ($ / kW)	Fixed O&M ($ / kW-yr)	Variable O&M ($ / MWh)	HHV Heat Rate (Btu/kWh)	Escalation Rate (%/year)
Geothermal	Coal								
Hydro New Small	Coal								
Hydro Pumped Storage	Coal								
CCCT (1x1)	Natural Gas	GE 7FA.05 ACC[1]	308	$17,854	$1,400	$10	$3	6,528	2.0%
CCCT (Duct Firing)	Waste Heat	GE 7FA.05 ACC[1]	40	$0	$0	$12	$0	8,546	2.0%
SCCT - Small Aeroderivative	Natural Gas	PW FT8	53	$3,599	$1,017	$6.05	$5	10,500	2.0%
SCCT - Large Aeroderivative	Natural Gas	GE LMS100	93	$7,502	$1,187	$17	$3	8,867	2.0%
SCCT - Frame	Natural Gas	GE 7EA	79	$6,753	$997	$12	$3	11,286	2.0%
ICE - Internal Combustion Engine	Natural Gas	Wartsila 18V50SG	18	$0	$1,280	$11	$5	8,314	2.0%
Utility Scale Solar PV[2]	Solar		25		$3,176	$43	$1		-1.0%
Wind[3]	Wind		40		$1,980	$38	$2		-0.5%

Table Notes:

Capacity for natural gas-fired resources estimated at 3,500 ft. elevation

[1] ACC = Air Cooled Condenser

[2] Solar fixed O&M is priced in $/kWdc.

[3] Based on build-transfer bids received in NWE's 2015 CREP RFP

ANNUAL NOMINAL LEVELIZED RESOURCE FIXED COSTS
$/KW INSTALLED

Resource	MW	Life	TPVRR Factor	LVLCR Factor	Carrying Charge	2015$ Capital/kW	Annual Nominal Levelized Cost: Inflation = 2.0% 2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Combined Cycle (natural gas)1	307.7	30	1,250	0.08084	10.10%	$ 1,400	$ 144	$ 147	$ 150	$ 153	$ 156	$ 159	$ 162	$ 166	$ 169	$ 172	$ 176
Small Aeroderivative (natural gas)	53	30	1,250	0.08084	10.10%	$ 1,017	$ 105	$ 107	$ 109.05	$ 111	$ 113	$ 116	$ 118	$ 120	$ 123	$ 125	$ 128
Large Aeroderivative (natural gas)	93.2	30	1,250	0.08084	10.10%	$ 1,087	$ 112	$ 114	$ 117	$ 119	$ 121	$ 124	$ 126	$ 129	$ 131	$ 134	$ 137
Frame Turbine (natural gas)	79.2	30	1,250	0.08084	10.10%	$ 997	$ 103	$ 105	$ 107	$ 109	$ 111	$ 113	$ 116	$ 118	$ 120	$ 123	$ 125
IC - Recip Engine (natural gas)	18.4	30	1,250	0.08084	10.10%	$ 1,280	$ 132	$ 135	$ 137	$ 140	$ 143	$ 146	$ 149	$ 152	$ 155	$ 158	$ 161
Solar PV2	25	30	1,250	0.08084	10.10%	$ 3,176	$ 311	$ 300	$ 296	$ 294	$ 293	$ 292	$ 292	$ 292	$ 292	$ 292	$ 292
Wind3	25	30	1,250	0.08084	10.10%	$ 1,980	$ 199	$ 198	$ 197	$ 196	$ 195	$ 194	$ 193	$ 192	$ 191	$ 190	$ 189
Hydro - Montana Small Scale	15	40	1,246	0.07528	9.38%	$ 1,600	$ 153	$ 156	$ 159	$ 163	$ 166	$ 169	$ 172	$ 176	$ 179	$ 183	$ 187
Battery	18	7	1,118	0.18575	20.77%	$ 654	$ 60	$ 56	$ 53	$ 50	$ 47	$ 44	$ 41	$ 39	$ 37	$ 34	$ 32

1 ACC = Air Cooled Condenser
2 Solar is priced in $/kWdc.
3 Based on build-transfer bids received in NWE's 2015 CREP RFP

Resource Carrying Charges:

Marginal Cost of Capital: 7.03%

Resource Life	TPVRR	LVLCR	RCC
20	$1,213	0.09462	11.48%
30	$1,250	0.08084	10.10%
40	$1,246	0.07528	9.38%

TPVRR = Total Present Value of Revenue Requirement

LVLCR = Levelized Cost Recovery Factor = Uniform Cost Recovery Factor
(i*(1+i)^n / (1+i)^n - 1)

RCC = Resource Carrying Charge

WACC:

	Allocation	Cost / Return	Weighted Cost
Debt Capital	52%	4.3%	2.23%
Equity Capital	48%	10.0%	4.80%
WACC			7.03%

Comparison of Average Annual Rates

Table 4.

Average Annual Rates for 25-Year Contracts at Current Rates		
Resource Type	Without Carbon	With Carbon
Non-Wind [1]	$0.06235	NA
Wind [1]	$0.05439	NA
Non-Wind (Solar) [2]	$0.06609	NA

[1] Annual average rate
[2] Option 1(a) Rate - modeled production, page 9, Exhibit__(JBB-4)

Effective Average Annual Rates for 25-Year Contracts at Proposed Rates		
Resource Type	Without Carbon	With Carbon
Hydroelectric and Other QF [3]	$0.03445	$0.04559
Wind [4]	$0.02909	$0.04079
Solar [5]	$0.03276	$0.04398

[3] 57% annual capacity factor, 36.9% capacity contribution
[4] 38% annual capacity factor, 5% capacity contribution
[5] Modeled solar PV production, page 10, Exhibit__(JBB-4)

Table 5. Changes from prefiled direct and prefiled supplemental to rebuttal

	Prefiled		Rebuttal		Change	
QF Resource Type	Without Carbon	With Carbon	Without Carbon	With Carbon	Without Carbon	With Carbon
Hydroelectric and Other QF	$0.03580	$0.04570	$0.03445	$0.04559	-3.77%	-0.24%
Wind	$0.03002	$0.04166	$0.02909	$0.04079	-3.09%	-2.08%
Solar	$0.03405	$0.04366	$0.03276	$0.04398	-3.78%	0.74%

Calculation of Overpayments to Solar PV Projects

Without Environmental Benefits

	Anaconda	Billings Broadview	Townsend	Great Falls	Bozeman Belgrade	Missoula	Average
NREL System Advisory Model - Production							
On Peak Production (kWh)	2,455,668	2,281,279	2,427,902	2,317,410	2,215,771	2,299,676	
Off Peak Production (kWh)	4,998,079	4,669,833	4,887,533	4,841,221	4,734,521	4,659,905	
Annual Production	7,453,747	6,951,112	7,315,435	7,158,631	6,950,292	6,959,581	7,131,466
Solar PV Revenues at Current QF-1 Option 1(a) Rates							
On Peak Rate ($/kWh)	$0.09273	$0.09273	$0.09273	$0.09273	$0.09273	$0.09273	
Off Peak Rate ($/kWh)	$0.05314	$0.05314	$0.05314	$0.05314	$0.05314	$0.05314	
On Peak Revenues	$227,714	$211,543	$225,139	$214,893	$205,468	$213,249	
Off Peak Revenues	$265,598	$248,155	$259,724	$257,262	$251,592	$247,627	
Total Revenues	$493,312	$459,698	$484,863	$472,156	$457,061	$460,876	$471,328
Ave. Rate	$0.06618	$0.06613	$0.06628	$0.06596	$0.06576	$0.06622	**$0.06609**
Proposed Solar Rates and Revenues							
Energy Rate ($/kWh)	$0.02805	$0.02805	$0.02805	$0.02805	$0.02805	$0.02805	
Energy Revenues	$209,078	$194,979	$205,198	$200,800	$194,956	$195,216	
Capadity Rate ($/kW-year)	$116.73	$116.73	$116.73	$116.73	$116.73	$116.73	
9.6% Capacity Contr. (kW)	288	288	288	288	288	288	
Capacity Revenues	$33,618	$33,618	$33,618	$33,618	$33,618	$33,618	
Total Revenues	$242,696	$228,597	$238,816	$234,418	$228,574	$228,834	$233,656
Ave. Rate	$0.03256	$0.03289	$0.03265	$0.03275	$0.03289	$0.03288	**$0.03276**

Difference in Revenues over Life of 25-Year Contract - Including Degradation of Energy Revenues due to Solar Degradation

Contract Year	Solar Degradation (0.75%/Yr)	Anaconda ($)	Broadview ($)	Townsend ($)	Great Falls ($)	Belgrade ($)	Missoula ($)	Average ($)
1	100.00%	$250,616	$231,101	$246,047	$237,738	$228,487	$232,042	
2	99.25%	$248,484	$229,116	$243,949	$235,703	$226,521	$230,049	
3	98.50%	$246,353	$227,130	$241,852	$233,668	$224,555	$228,057	
4	97.75%	$244,221	$225,145	$239,754	$231,633	$222,590	$226,064	
5	97.00%	$242,089	$223,159	$237,657	$229,597	$220,624	$224,072	
6	96.25%	$239,957	$221,174	$235,559	$227,562	$218,658	$222,080	
7	95.50%	$237,826	$219,189	$233,462	$225,527	$216,692	$220,087	
8	94.75%	$235,694	$217,203	$231,364	$223,492	$214,726	$218,095	
9	94.00%	$233,562	$215,218	$229,267	$221,457	$212,761	$216,102	
10	93.25%	$231,430	$213,232	$227,169	$219,422	$210,795	$214,110	
11	92.50%	$229,299	$211,247	$225,072	$217,386	$208,829	$212,117	
12	91.75%	$227,167	$209,262	$222,974	$215,351	$206,863	$210,125	
13	91.00%	$225,035	$207,276	$220,877	$213,316	$204,897	$208,132	
14	90.25%	$222,903	$205,291	$218,779	$211,281	$202,932	$206,140	
15	89.50%	$220,772	$203,305	$216,682	$209,246	$200,966	$204,148	
16	88.75%	$218,640	$201,320	$214,584	$207,210	$199,000	$202,155	
17	88.00%	$216,508	$199,335	$212,487	$205,175	$197,034	$200,163	
18	87.25%	$214,376	$197,349	$210,389	$203,140	$195,069	$198,170	
19	86.50%	$212,245	$195,364	$208,292	$201,105	$193,103	$196,178	
20	85.75%	$210,113	$193,379	$206,194	$199,070	$191,137	$194,185	
21	85.00%	$207,981	$191,393	$204,097	$197,035	$189,171	$192,193	
22	84.25%	$205,849	$189,408	$201,999	$194,999	$187,205	$190,200	
23	83.50%	$203,717	$187,422	$199,902	$192,964	$185,240	$188,208	
24	82.75%	$201,586	$185,437	$197,804	$190,929	$183,274	$186,215	
25	82.00%	$199,454	$183,452	$195,707	$188,894	$181,308	$184,223	
	Total Overpay:	**$5,625,877**	**$5,181,907**	**$5,521,921**	**$5,332,900**	**$5,122,437**	**$5,203,310**	**$5,331,392**
	NPV Overpay:	**$2,698,976**	**$2,486,841**	**$2,649,304**	**$2,558,988**	**$2,458,426**	**$2,497,068**	**$2,558,267**

No. Solar PV Projects	**33**	**33**	**33**	**33**	**33**	**33**	**33**
Grand Total Overpay:	**$185,653,934**	**$171,002,918**	**$182,223,379**	**$175,985,705**	**$169,040,431**	**$171,709,242**	**$175,935,935**
Grand Total NPV:	**$89,066,200**	**$82,065,767**	**$87,427,039**	**$84,446,602**	**$81,128,067**	**$82,403,257**	**$84,422,822**

Calculation of Average Annual Rate Solar PV Projects

With Environmental Benefits

	Anaconda	Billings Broadview	Townsend	Great Falls	Bozeman Belgrade	Missoula	Average
NREL System Advisory Model - Production							
On Peak Production (kWh)	2,455,668	2,281,279	2,427,902	2,317,410	2,215,771	2,299,676	
Off Peak Production (kWh)	4,998,079	4,669,833	4,887,533	4,841,221	4,734,521	4,659,905	
Annual Production	7,453,747	6,951,112	7,315,435	7,158,631	6,950,292	6,959,581	7,131,466
Solar PV Revenues at Current QF-1 Option 1(a) Rates							
On Peak Rate ($/kWh)	$0.09273	$0.09273	$0.09273	$0.09273	$0.09273	$0.09273	
Off Peak Rate ($/kWh)	$0.05314	$0.05314	$0.05314	$0.05314	$0.05314	$0.05314	
On Peak Revenues	$227,714	$211,543	$225,139	$214,893	$205,468	$213,249	
Off Peak Revenues	$265,598	$248,155	$259,724	$257,262	$251,592	$247,627	
Total Revenues	$493,312	$459,698	$484,863	$472,156	$457,061	$460,876	$471,328
Ave. Rate	$0.06618	$0.06613	$0.06628	$0.06596	$0.06576	$0.06622	**$0.06609**
Proposed Solar Rates and Revenues							
Energy Rate ($/kWh)	$0.03927	$0.03927	$0.03927	$0.03927	$0.03927	$0.03927	
Energy Revenues	$292,709	$272,970	$287,277	$281,119	$272,938	$273,303	
Capadity Rate ($/kW-year)	$116.73	$116.73	$116.73	$116.73	$116.73	$116.73	
9.6% Capacity Contr. (kW)	288	288	288	288	288	288	
Capacity Revenues	$33,618	$33,618	$33,618	$33,618	$33,618	$33,618	
Total Revenues	$326,327	$306,588	$320,895	$314,738	$306,556	$306,921	$313,671
Ave. Rate	$0.04378	$0.04411	$0.04387	$0.04397	$0.04411	$0.04410	**$0.04398**

(7) The recommended methodology to evaluate the net planning capability established for wind or solar facilities shall be determined on a monthly basis, as stated below. If a member's desire to use a more restrictive methodology to evaluate the net capability of wind or solar they may do so, however net capability determined by the alternative methodology employed cannot credit the wind or solar with a capability greater than determined with the methodology stated below:

(a) Assemble all available hourly net power output (MWH) data measured at the system interconnection point.

(b) Select the hourly net power output values occurring during the top 3% of load hours for the SPP Load Serving Entity for each month of each year for the evaluation period.

(c) Select the hourly net power output value that can be expected from the facility 60% of the time or greater. For example, for a 5 year period with the 110 hourly net power output values ranked from highest to lowest, the capacity of the facility will be the MW value in the 65th data point.

(d) A seasonal or annual net capability may be determined by selecting the appropriate monthly MW values corresponding to the Load Serving Entity's peak load month of the season of interest (e.g., 22 hours for a typical 30 day month and 110 hours for a 5 year period).

(e) Facilities in commercial operation 3 years or less:

(i) The data must include the most recent 3 years.

(ii) Values may be calculated from wind or solar data, if measured MW values are not yet available. Wind data correlated with a reference tower beyond fifty miles is subject to Generation Working Group approval. Solar data correlated with a reference measuring device beyond two hundred miles is subject to Generation Working Group approval. For calculated values, at least one year must be based on site specific data.

(iii) If the Load Serving Entity chooses not to perform the net capability calculations as described above during the first 3 years of commercial operation, the Load Serving Entity may submit 5% for wind facilities and 10% for solar facilities of the site facility's nameplate rating.

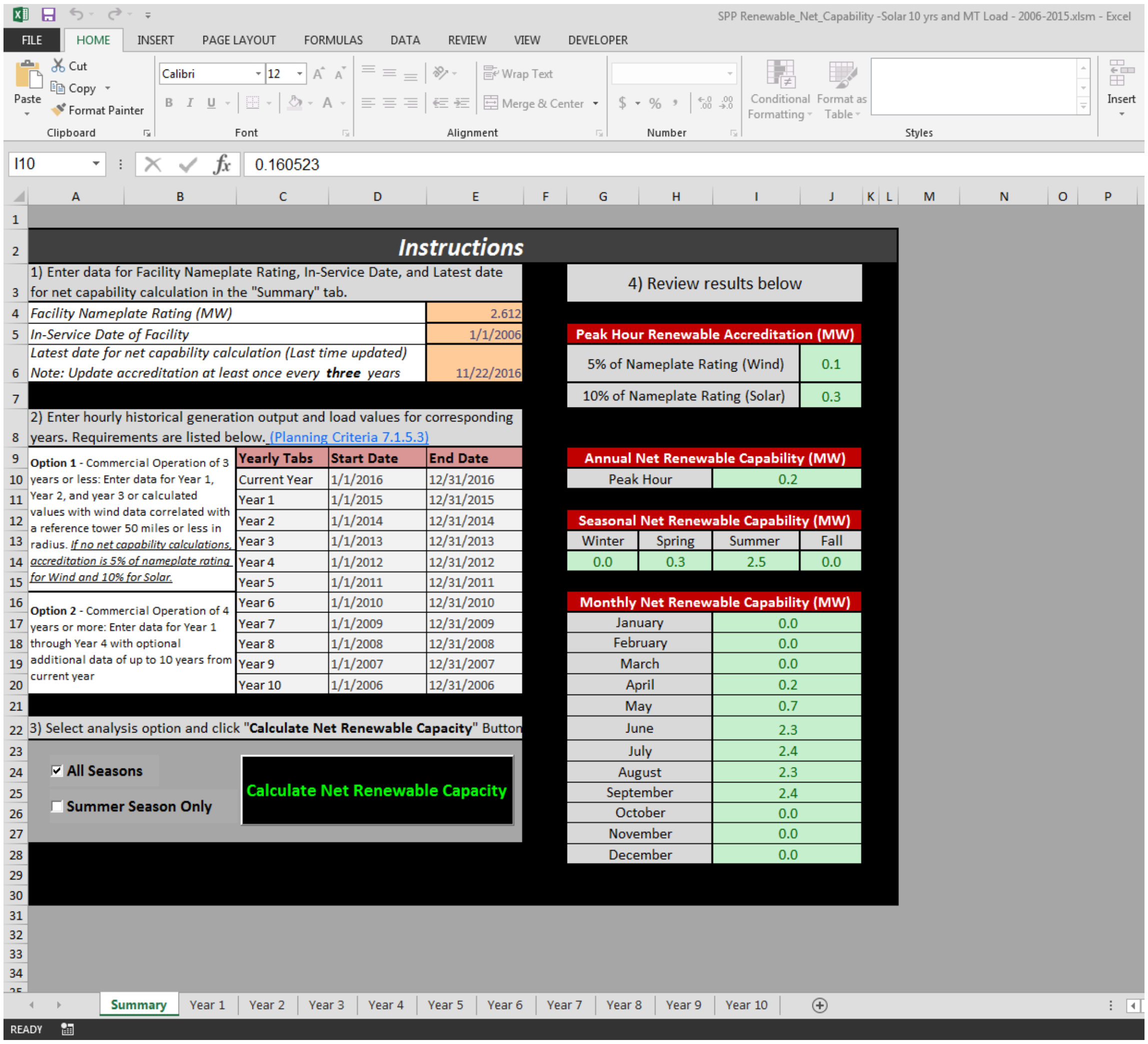
(f) Facilities in commercial operation 4 years and greater:

(i) The data must include all available data up to the most recent 10 years of commercial operation.

(ii) Only metered hourly net power output (MWH) data may be used.

(iii) After three years of commercial operations, if the Load Serving Entity does not perform or provide the net capability calculations to SPP as described above, then the net capability for the resource will be 0 MW.

(g) The net capability calculation shall be updated at least once every three years.



SPP Renewable_Net_Capability -Solar 10 yrs and MT Load - 2006-2015.xlsm - Excel

I10 | 0.160523

Instructions

1) Enter data for Facility Nameplate Rating, In-Service Date, and Latest date for net capability calculation in the "Summary" tab.

Facility Nameplate Rating (MW)	2.612
In-Service Date of Facility	1/1/2006
Latest date for net capability calculation (Last time updated) *Note: Update accreditation at least once every* ***three*** *years*	11/22/2016

2) Enter hourly historical generation output and load values for corresponding years. Requirements are listed below. (Planning Criteria 7.1.5.3)

	Yearly Tabs	Start Date	End Date
Option 1 - Commercial Operation of 3 years or less: Enter data for Year 1, Year 2, and year 3 or calculated values with wind data correlated with a reference tower 50 miles or less in radius. *If no net capability calculations, accreditation is 5% of nameplate rating for Wind and 10% for Solar.*	Current Year	1/1/2016	12/31/2016
	Year 1	1/1/2015	12/31/2015
	Year 2	1/1/2014	12/31/2014
	Year 3	1/1/2013	12/31/2013
	Year 4	1/1/2012	12/31/2012
	Year 5	1/1/2011	12/31/2011
Option 2 - Commercial Operation of 4 years or more: Enter data for Year 1 through Year 4 with optional additional data of up to 10 years from current year	Year 6	1/1/2010	12/31/2010
	Year 7	1/1/2009	12/31/2009
	Year 8	1/1/2008	12/31/2008
	Year 9	1/1/2007	12/31/2007
	Year 10	1/1/2006	12/31/2006

3) Select analysis option and click "**Calculate Net Renewable Capacity**" Button

☑ **All Seasons**
☐ **Summer Season Only**

Calculate Net Renewable Capacity

4) Review results below

Peak Hour Renewable Accreditation (MW)	
5% of Nameplate Rating (Wind)	0.1
10% of Nameplate Rating (Solar)	0.3

Annual Net Renewable Capability (MW)	
Peak Hour	0.2

Seasonal Net Renewable Capability (MW)

Winter	Spring	Summer	Fall
0.0	0.3	2.5	0.0

Monthly Net Renewable Capability (MW)	
January	0.0
February	0.0
March	0.0
April	0.2
May	0.7
June	2.3
July	2.4
August	2.3
September	2.4
October	0.0
November	0.0
December	0.0

Summary | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10

READY

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2016.5.39
Avoided Cost Rate Filing
NorthWestern Energy

PREFILED REBUTTAL TESTIMONY

OF MICHAEL R. CASHELL

ON BEHALF OF NORTHWESTERN ENERGY

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Witness Information

Q. Please state your name and business address.

A. My name is Michael R. Cashell. I work at 11 East Park Street, Butte, Montana 59701.

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

A. I am NorthWestern Energy's ("NorthWestern") Vice President - Transmission.

Q. Please summarize your education and employment experience.

A. I graduated from Montana Tech of the University of Montana in Butte, Montana, receiving a Bachelor of Science degree in Engineering Science in 1986. I also attended the University of Idaho's Public Utilities Executive Course in 1997. I have been certified as a North American Electric Reliability Corporation ("NERC") System Operator. I have worked in the electric and natural gas utility industry for over 30 years, employed first by the Montana Power Company ("MPC") and now by NorthWestern. My experience is primarily in the areas of electric and gas transmission system operations and maintenance, substation operations and maintenance, balancing authority area operation, tariff and contract administration, bulk power supply and operations, hydroelectric and thermal electric generation plant optimization, and independent power production.

Q. What are your responsibilities as Vice President - Transmission?

A. I am responsible for all aspects of NorthWestern's electric and natural gas transmission systems and substations in Montana and South Dakota, including the systems' safe, reliable and efficient operation, transmission services, operations, planning, engineering, and maintenance. I am also responsible for the activities related to transmission and transportation contracts, interconnection agreements with all facilities, including Qualifying Facilities ("QFs"), and transmission service under

NorthWestern's Federal Energy Regulatory Commission ("FERC") Open Access Transmission Tariff for our wholesale and unbundled retail customers, procurement of ancillary services products, and compliance activities related to all FERC regulation and NERC reliability and cyber security standards. I am also responsible for all natural gas transportation service under Montana Public Service Commission ("MPSC" or "Commission") tariffs. Compliance requirements for which I am responsible include Western Electricity Coordinating Council (in Montana) and Midwest Reliability Organization criteria (in South Dakota), both of which are NERC regional entities, and FERC criteria as well as all Department of Transportation, Pipeline Hazardous Materials Safety Administration ("PHMSA"), and MPSC and South Dakota Public Utilities Commission natural gas transmission and storage regulation.

Purpose of Testimony

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

A. The purpose of my testimony is to address and rebut the claim by Mr. R. Thomas Beach on behalf of the Montana Environmental Information Center/Vote Solar that the QF-1 avoided costs are understated by avoided transmission costs. I will explain the flaws in his analysis.

Q. Briefly stated, what is the basis for Mr. Beach's claim that the QF-1 avoided cost rates are understated by his measure of avoided transmission costs?

A. Mr. Beach claims that the purchase of intermittent solar QF power connected at the distribution level on the NorthWestern electric system will avoid costs at the transmission level of the electric system. His argument ignores the difference between intermittent and firm power and misuses the concept of avoided cost. NorthWestern could not design its transmission system in a fashion which would produce avoidable transmission costs as suggested by Mr. Beach.

Q. Why did you say that Mr. Beach's argument misuses the concept of avoided cost?

A. Avoided costs are the incremental costs that NorthWestern avoids by purchasing power from a QF, such as a 3-megawatt ("MW") solar generator. NorthWestern's transmission system is not a future resource, like a planned generating addition, that can be avoided or postponed. It is an existing system which was built primarily to meet the needs of NorthWestern's distribution and transmission customers. The cost of the transmission system is primarily a sunk cost, or an operating and maintenance cost associated with a sunk cost. The cost of owning and operating NorthWestern's transmission system is based upon the capacity required to serve all customers at peak load. The costs of the transmission system are not avoidable in the way that the incremental costs of generation can sometimes be avoided.

Q. Mr. Beach represents that there are potential benefits to the transmission system from relatively small, 3-MW solar QFs locating on NorthWestern's system. Do you agree with that premise?

A. No, I do not.

Q. Would you be more specific?

A. Yes. Mr. Beach claims that these small, 3-MW solar projects will typically interconnect to the distribution system and that the power produced will generally serve load on the distribution system. And, he claims that as a result, these small, distributed solar projects internal to the NorthWestern system may reduce peak loads on the transmission systems to which they interconnect. There is a fundamental flaw in his conclusion that these projects could somehow result in avoided transmission costs. While solar generation does produce energy <u>at certain times</u>, solar generation is intermittent and affected by such things as cloud cover, storms, time of day, and time of year. NorthWestern cannot rely on or plan for its peak loading to be met, in any part, by this type of distributed, intermittent generation. In fact, should these facilities interconnect to the distribution system, NorthWestern's distribution and transmission planning processes must then plan for <u>both</u> situations – when the solar generation is online at maximum and when it is not available at all. So, from a planning and capacity standpoint, there is little to no capacity value in the interconnection of these small solar projects to either the distribution system or the transmission system. This means that NorthWestern will still need to make the investments that are necessary for load growth on its distribution system regardless of the solar installations. This planning on the distribution system ultimately leads to transmission system investment. Compounding the situation is the potential need to upgrade a distribution feeder or substation if it has not been designed to accommodate excess generation.

Q. Are there any other flaws in Mr. Beach's argument?

A. Yes. Mr. Beach contends that the avoided cost on NorthWestern's system can be shown as a function of making more transmission capacity available for wholesale activity. For most, if not all, of the solar projects seeking to interconnect to our system, as Mr. Beach notes, developers are searching for locations on our distribution system to interconnect. And, ideally, they are looking for locations near substations with unutilized capacity. The transmission that serves NorthWestern's distribution system is primarily lower voltage, sometimes radial in nature, and generally it is not part of our bulk electric system which is used for wholesale activity. As a result, the notion that the solar generation would free up NorthWestern's transmission system for additional wholesale activity and revenue generation is not realistic. And, as a result, the calculated potential savings based upon NorthWestern's Open Access Tariff rates is similarly misguided.

Q. Why did you say NorthWestern could not design and operate its transmission system in a fashion which would produce avoidable transmission costs as hypothesized by Mr. Beach?

A. As previously stated, a transmission system must be designed to meet the peak load requirements of its customers. Conductors, substations, and transformers are not sized to meet average load conditions. They are necessarily sized to meet peak load conditions, conditions which are not ameliorated by solar generation during the dark days of winter in the northern latitudes or under other conditions like cloud cover or night. Adding intermittent generating resources at the distribution level on the NorthWestern system does not decrease transmission costs.

Q. Have you reviewed the "Peak Capacity Allocation Factor" (PCAF) approach that results in Mr. Beach's conclusion on page 36 of his Pre-filed Direct Testimony that solar QFs can avoid transmission costs equal to 49% of their nameplate?

A. Yes. NorthWestern has reviewed the testimony and the related analysis provided in response to Data Request NWE-001. The analysis is very involved and complicated. Fundamentally, NorthWestern understands Mr.

Beach's conclusion to be an estimate of the average impact that the output of a typical solar QF might have on the loading of a hypothetical transmission substation on NorthWestern's system. NorthWestern cannot rely on estimated average impacts for transmission planning. Rather, as explained earlier in my testimony, we must plan for the extreme situations – when the solar generation is producing at maximum and when it is not available at all.

Additionally, as I discussed previously, the notion that solar generation projects interconnected to our distribution system would free up NorthWestern's transmission system for additional wholesale activity as indicated in footnote 55 of Mr. Beach's testimony is not realistic. Even if that notion were correct, NorthWestern could not sell this "freed up capacity" as firm because the output that frees up the capacity is intermittent.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2016.5.39
Avoided Cost Rate Filing
NorthWestern Energy

PREFILED REBUTTAL TESTIMONY

OF LUKE P. HANSEN

ON BEHALF OF NORTHWESTERN ENERGY

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Witness Information

Q. Please state your name and business address.

A. My name is Luke P. Hansen, and my business address is 11 East Park Street, Butte, Montana 59701.

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

A. I am employed by NorthWestern Energy ("NorthWestern") as a senior analyst in Energy Supply.

Q. Are you the same Luke P. Hansen who submitted prefiled direct testimony in this docket?

A. Yes.

Purpose of Testimony

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

A. The purpose of my testimony is to rebut claims made by Vote Solar and Montana Environmental Information Center witness R. Thomas Beach and FLS Energy and Cypress Creek Renewables witness Roger Schiffman and to update the energy rates that were calculated for wind, solar, and hydro Qualifying Facility ("QF") resources using PowerSimm™.

<u>Rebuttal of Pre-filed Direct Testimony of R. Thomas Beach</u>

Q. On page 12, line 24 of his testimony, Mr. Beach said he used a natural gas price forecast from September 1, 2016 that is 3% higher than the forecast NorthWestern used in its 2015 Electricity Supply Resource Procurement Plan ("2015 Plan"). Has NorthWestern updated its natural gas forecast and, if so, is the price higher or lower than the 2015 Plan forecast?

A. NorthWestern updated its natural gas and electric forecast at the close of business on November 17, 2016. The Intercontinental Exchange ("ICE") forecast was used through 2019, and after 2019 the forecast was escalated using the 2016 Energy Information Administration ("EIA") nominal Henry Hub natural gas forecast. NorthWestern used the 2016 EIA escalation for the updated commodity forecasts compared to the 2015 EIA escalation that was used for the 2015 Plan price forecast. The pipeline transportation tariffs for TransCanada and NorthWestern were updated and added to the forecast. Table 1 below details that current natural gas prices are 12% lower than those used in the 2015 Plan.

Table 1

	2015 RPP Forecast	11.17.2016 Forecast	Decrease in Forecasts
	($/MMBtu)	($/MMBtu)	($/MMBtu)
2017	$ 2.63	$ 2.54	$ (0.09)
2018	$ 2.84	$ 2.63	$ (0.21)
2019	$ 3.00	$ 2.65	$ (0.35)
2020	$ 3.14	$ 2.93	$ (0.20)
2021	$ 3.24	$ 2.94	$ (0.30)
2022	$ 3.36	$ 3.02	$ (0.34)
2023	$ 3.47	$ 3.30	$ (0.17)
2024	$ 3.60	$ 3.51	$ (0.09)
2025	$ 3.72	$ 3.65	$ (0.07)
2026	$ 3.86	$ 3.64	$ (0.21)
2027	$ 4.00	$ 3.70	$ (0.30)
2028	$ 4.14	$ 3.80	$ (0.34)
2029	$ 4.29	$ 3.91	$ (0.38)
2030	$ 4.45	$ 3.99	$ (0.45)
2031	$ 4.61	$ 4.05	$ (0.56)
2032	$ 4.78	$ 4.15	$ (0.62)
2033	$ 4.95	$ 4.20	$ (0.75)
2034	$ 5.14	$ 4.28	$ (0.86)
2035	$ 5.33	$ 4.35	$ (0.98)
2036	$ 5.53	$ 4.43	$ (1.10)
2037	$ 5.74	$ 4.48	$ (1.26)
2038	$ 5.95	$ 4.53	$ (1.42)
2039	$ 6.18	$ 4.68	$ (1.50)
2040	$ 6.41	$ 4.79	$ (1.62)
2041	$ 6.66	$ 4.90	$ (1.76)
2042	$ 6.91	$ 5.01	$ (1.90)
Levelized	$3.96	$3.50	$ (0.46)
Percentage change in forecasts			-12%

Q. On page 14, lines 3-5, Mr. Beach assigns a value of $5 per Renewable Energy Credit ("REC") for 2017 increasing with inflation through 2021. Is this the current value of a REC that NorthWestern would use

if it needed to purchase RECs to satisfy its renewable portfolio standard ("RPS") obligation?

A. No. NorthWestern assigned a value of $.90 per REC in 2017 in its 2015 Plan. NorthWestern has received a broker quote from December 5, 2016 for RECs that NorthWestern could use to fulfill its RPS obligation for the back half of 2016/front half of 2017 with a bid/ask range of $.33-$.38. NorthWestern has also monetized RECs in South Dakota for the back half of 2015 for $.29.

Q. Does NorthWestern need RECs from 2017-2021 from a QF-1 resource to fulfill it RPS obligation?

A. No. NorthWestern estimated, in its 2015 Plan, that it will have enough RECs through 2026 to meet its RPS obligation with renewable generation from Company-owned and currently contracted renewable resources.

Q. On page 13, line 14, Mr. Beach discusses the sale of RECs that are included in the environmental attributes to NorthWestern. Is NorthWestern required under the Public Utility Regulatory Policies Act to purchase the environmental attributes from a QF project?

A. No. QF-1 renewable projects can keep the environmental attributes and receive a non-carbon price for their energy output or sell the environmental attributes to NorthWestern at the provided carbon-included rate.

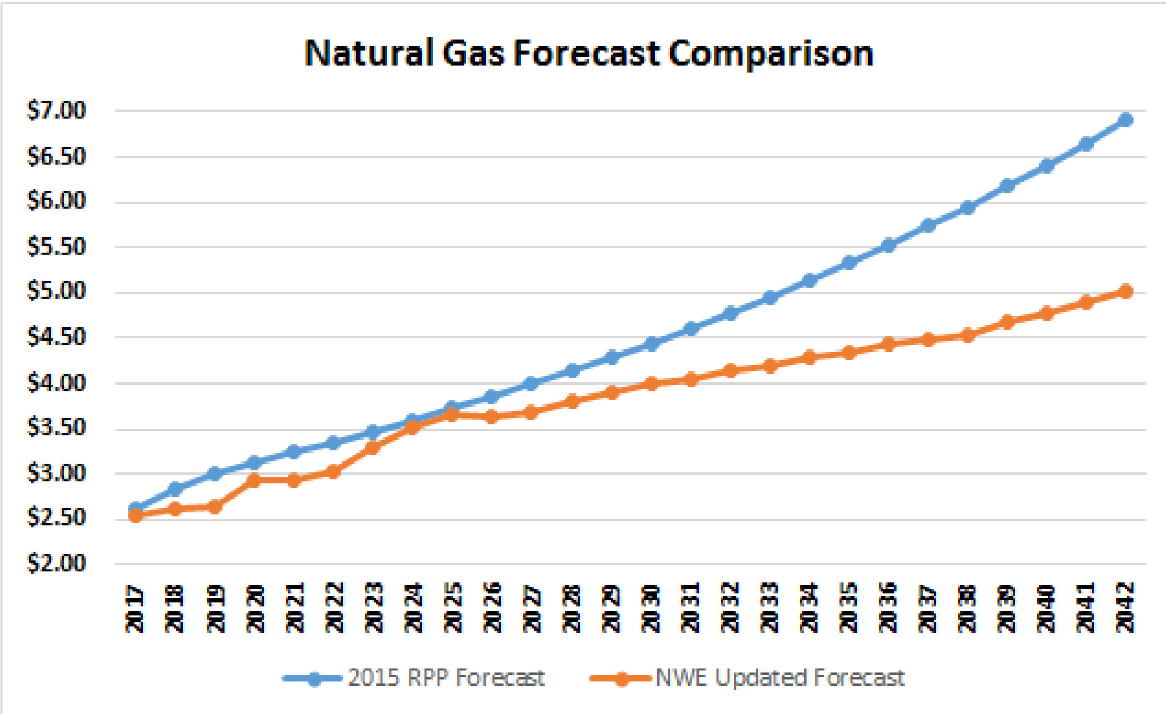
Q. On page 19 of his testimony, Mr. Beach asserts that NorthWestern can reduce thermal generation and replace it with cheaper market power during "Long-2" hours. Is this assertion correct?

A. No. During "Long-2" hours the market price is below the variable cost of the thermal resources and those resources are not economically dispatched. The energy that is serving NorthWestern's load during "Long-2" conditions is from the hydroelectric assets, must-run thermal assets, and/or must-take QF resources. There is nothing that NorthWestern can avoid during the "Long-2" condition, and that is why NorthWestern values the energy provided during "Long-2" at zero.

Q. On page 19, line 16 through the chart on page 20, Mr. Beach states that NorthWestern has understated the natural gas costs with delivery within Montana. Do you agree?

A. No. As discussed above, natural gas prices have decreased by 12% since the 2015 Plan. Figure 1 below details the comparison of gas prices delivered to a burner tip in Montana using the forecast from the 2015 Plan and the updated forecast from November 17, 2016.

Figure 1



<u>Rebuttal of Prefiled Rebuttal Testimony of Roger Schiffman</u>

Q. On page 14, line 5, Mr. Schiffman states that NorthWestern has "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." Do you agree?

A. No. NorthWestern simulated in PowerSimm, on an hourly time-step, the portfolio and the portfolio with the QF resource. The hourly simulation simulates the weather, load, renewable generation, commodity prices, and economic thermal generation of NorthWestern's supply portfolio. The dispatch of all generation assets in each of the portfolios is compared against the load to determine for each hour if NorthWestern is in a net purchase or a net sale position. The comparison of the two portfolios explicitly details the effect of the QF generation on NorthWestern's supply portfolio. The foundation for the energy rate that is calculated for the QF resource is the PowerSimm modeling results.

Q. On page 17, line 20, through page 18, line 17 Mr. Schiffman disputes the basis adjustment from Mid-C. Do you agree with his assertion?

A. No. NorthWestern has historically been able to procure energy in Montana at a discount to Mid-C because of the incentive to sell energy that is produced in Montana to buyers in Montana. If this energy is transported to Mid-C it has to cross both NorthWestern's and the Bonneville Power Administration's ("BPA") transmission lines. The tariff for NorthWestern's transmission is $4.33 plus 4% losses, and the tariff for BPA is $4.28 plus 2% losses.

NorthWestern is most often in a selling position during light load hours. During light load hours, as there is a reduced demand for energy in Montana, NorthWestern would have to pay full transmission charges to transmit this energy to Mid-C.

<u>NorthWestern's Current Avoided Cost for Energy</u>

Q. Has NorthWestern updated its QF-1 tariff long-term purchase prices of energy that can be avoided by purchasing the output of various types of QFs?

A. Yes. The costs for energy, exclusive of wind integration costs and capacity value necessary to make firm energy deliveries, that NorthWestern can avoid by purchasing the output of various types of QFs under the QF-1 tariff using the updated commodity price forecasts from November 17, 2016 are detailed in Table 2 below:

Table 2 Updated Proposed Energy Rates

Resource	Levelized energy rate without carbon price adder ($/MWh)	Levelized energy rate with carbon price adder ($/MWh)
Wind	$ 27.34	$ 39.04
Solar	$ 28.05	$ 39.27
Hydro	$ 25.89	$ 37.03

All of these are 25-year levelized avoided cost energy rates. Exhibit__(LPH-2) details the calculations of the avoided energy cost for a wind, a solar, and a hydro QF project using the PowerSimm™ modeling.

Q. Has NorthWestern updated any inputs or changed any methodology in the energy rate calculation performed for this rebuttal testimony compared to the energy rate calculation that was presented in the prefiled direct testimony?

A. Yes, four changes have been made in this energy rate calculation. First, NorthWestern has updated the natural gas and electricity price forecasts in this calculation. As discussed above, the commodity prices were updated using forecasts from November 17, 2016.

Second, the natural gas transportation charges were updated to account for current transportation charges on the TransCanada and NorthWestern pipelines, and the transportation charges on both pipelines have been included in the energy rate calculation.

Third, when NorthWestern performed the modeling in PowerSimm, 60% of the carbon price was added to the electricity price in the simulations. When the calculation was performed outside of PowerSimm to arrive at an energy rate without carbon, only 50% of the carbon price was removed from the electricity price with carbon instead of the 60% that was included in the modeling. The calculation to derive an energy rate without carbon now correctly reflects removal of 60% of the carbon price.

Finally, in the prefiled direct testimony, when NorthWestern calculated the energy rate in a long position, NorthWestern included Colstrip, Basin Creek, and Dave Gates Generating Station. NorthWestern is now correctly including these resources along with the other thermal resources identified in the Economically Optimal Portfolio (“EOP”) from the 2015 Plan. The other thermal resources included in this portfolio and the year that they are added to the EOP are as follows: an internal combustion engine in 2019, a combined cycle combustion turbine in 2025, and a frame combustion turbine in 2028.

Q. Has NorthWestern updated the energy rate calculation that was presented in the prefiled direct testimony to reflect the revised inputs and methodology described above?

A. Yes, with the exception of the update to reflect November 17, 2016 commodity prices which were not available at the time of the initial filing. Table 3 below details what energy rates would have been proposed in the initial prefiled direct testimony using all of the thermal resources in the EOP, the corrected energy rate without carbon, and the pipeline transportation charges for both TransCanada and NorthWestern.

Therefore, the only difference between Table 2 and Table 3 is that Table 3 is not updated to reflect commodity prices from November 17, 2016.

Table 3 Revised Initial Energy Rates

Resource	Levelized energy rate without carbon price adder ($/MWh)	Levelized energy rate with carbon price adder ($/MWh)
Wind	$ 28.08	$ 39.62
Solar	$ 29.15	$ 41.17
Hydro/Other	$ 27.02	$ 38.17

Q. To be clear, are NorthWestern's updated proposed energy rates as shown in Table 2?

A. Yes, NorthWestern's updated proposed QF-1 energy rates are shown in Table 2 above, and supported by the detailed calculations in Exhibit__(LPH-2).

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

WACC 7.03% nominal, annual

Summary: NPV and Annualized $/MWh of Energy Avoided Costs, WITHOUT Carbon Price Impact

NPV Of Energy Costs	$ 317.78	$/MWh
Levelized Payment	$ 27.34	$/MWh

Summary Table: Annual Wind QF Generation and Energy Avoided Costs WITHOUT Carbon Price Impacts

Year	Generation (MWh)	Offset Generation (MWh)	Offset Purchases (MWh)	Average Offset Generation Price ($/MWh)	Average Offset Purchase Price ($/MWh)	Total Offset Generation Energy Avoided Cost ($)	Total Energy Avoided Cost of Purchases ($)	Total Energy Avoided Cost ($)	Average Energy Avoided Cost ($/MWh)
2018	39,471	17,372	22,099	$ 11.61	$ 22.85	$ 201,717.60	$ 504,928.50	$ 706,646.10	$ 17.90
2019	39,471	17,472	21,999	$ 12.28	$ 23.62	$ 214,539.02	$ 519,705.01	$ 734,244.03	$ 18.60
2020	39,471	18,299	21,172	$ 13.67	$ 27.12	$ 250,080.96	$ 574,150.53	$ 824,231.49	$ 20.88
2021	39,471	18,551	20,920	$ 13.19	$ 27.22	$ 244,716.98	$ 569,510.76	$ 814,227.73	$ 20.63
2022	39,471	16,145	23,326	$ 13.13	$ 27.07	$ 211,932.87	$ 631,378.01	$ 843,310.88	$ 21.37
2023	39,471	17,140	22,331	$ 15.20	$ 30.40	$ 260,495.68	$ 678,793.03	$ 939,288.71	$ 23.80
2024	39,471	16,418	23,054	$ 11.19	$ 33.23	$ 183,768.11	$ 766,004.43	$ 949,772.54	$ 24.06
2025	39,471	27,941	11,530	$ 26.04	$ 32.66	$ 727,546.43	$ 376,559.43	$ 1,104,105.86	$ 27.97
2026	39,471	27,333	12,138	$ 25.71	$ 32.15	$ 702,641.87	$ 390,185.78	$ 1,092,827.65	$ 27.69
2027	39,471	23,785	15,686	$ 25.91	$ 33.06	$ 616,190.26	$ 518,655.51	$ 1,134,845.77	$ 28.75
2028	39,471	23,964	15,507	$ 27.73	$ 33.22	$ 664,575.43	$ 515,118.60	$ 1,179,694.03	$ 29.89
2029	39,471	22,282	17,189	$ 30.32	$ 32.43	$ 675,521.78	$ 557,524.51	$ 1,233,046.29	$ 31.24
2030	39,471	21,898	17,573	$ 30.71	$ 33.51	$ 672,436.70	$ 588,914.61	$ 1,261,351.31	$ 31.96
2031	39,471	21,169	18,302	$ 31.63	$ 33.80	$ 669,597.94	$ 618,604.80	$ 1,288,202.74	$ 32.64
2032	39,471	20,927	18,544	$ 32.58	$ 34.83	$ 681,787.48	$ 645,877.83	$ 1,327,665.30	$ 33.64
2033	39,471	20,021	19,450	$ 32.69	$ 35.40	$ 654,425.02	$ 688,575.22	$ 1,343,000.24	$ 34.02
2034	39,425	18,365	21,060	$ 33.20	$ 36.27	$ 609,706.66	$ 763,930.46	$ 1,373,637.13	$ 34.84
2035	39,471	17,968	21,503	$ 33.89	$ 36.69	$ 608,965.47	$ 788,978.96	$ 1,397,944.43	$ 35.42
2036	39,471	16,869	22,602	$ 34.42	$ 37.77	$ 580,610.38	$ 853,636.57	$ 1,434,246.95	$ 36.34
2037	39,471	15,409	24,062	$ 35.18	$ 38.33	$ 542,003.67	$ 922,295.76	$ 1,464,299.43	$ 37.10
2038	39,471	14,665	24,806	$ 35.62	$ 38.80	$ 522,425.18	$ 962,407.62	$ 1,484,832.80	$ 37.62
2039	39,471	14,477	24,994	$ 36.43	$ 40.37	$ 527,334.74	$ 1,008,909.53	$ 1,536,244.26	$ 38.92
2040	39,471	14,213	25,258	$ 37.58	$ 41.18	$ 534,149.20	$ 1,040,059.26	$ 1,574,208.47	$ 39.88
2041	39,291	12,834	26,456	$ 38.31	$ 42.40	$ 491,659.38	$ 1,121,655.49	$ 1,613,314.87	$ 41.06
2042	39,292	12,325	26,967	$ 39.16	$ 43.58	$ 482,680.45	$ 1,175,230.14	$ 1,657,910.59	$ 42.19

WACC 7.03% nominal, annual

Summary: NPV and Annualized $/MWh of Energy Avoided Costs, WITHOUT Carbon Price Impact

NPV Of Energy Costs	$	325.97	$/MWh
Levelized Payment	$	28.05	$/MWh

Summary Table: Annual Solar QF Generation and Energy Avoided Costs WITHOUT Carbon Price Impacts

Year	Generation (MWh)	Offset Generation (MWh)	Offset Purchases (MWh)	Average Offset Generation Price ($/MWh)	Average Offset Purchase Price ($/MWh)	Total Offset Generation Energy Avoided Cost ($)	Total Energy Avoided Cost of Purchases ($)	Total Energy Avoided Cost ($)	Average Energy Avoided Cost ($/MWh)
2018	19,947	6,672	13,275	$ 11.82	$ 22.31	$ 78,847.98	$ 296,170.89	$ 375,018.86	$ 18.80
2019	19,800	6,421	13,379	$ 12.54	$ 23.04	$ 80,514.68	$ 308,305.07	$ 388,819.75	$ 19.64
2020	19,652	6,682	12,970	$ 14.31	$ 26.43	$ 95,639.25	$ 342,816.97	$ 438,456.22	$ 22.31
2021	19,503	7,214	12,289	$ 13.45	$ 26.71	$ 97,006.74	$ 328,206.69	$ 425,213.43	$ 21.80
2022	19,359	5,615	13,744	$ 13.38	$ 26.40	$ 75,134.85	$ 362,868.37	$ 438,003.22	$ 22.63
2023	19,212	5,919	13,293	$ 17.07	$ 29.66	$ 101,014.67	$ 394,314.68	$ 495,329.35	$ 25.78
2024	19,068	5,919	13,149	$ 8.63	$ 32.69	$ 51,083.07	$ 429,897.11	$ 480,980.18	$ 25.22
2025	18,925	12,069	6,856	$ 25.99	$ 31.49	$ 313,617.75	$ 215,873.07	$ 529,490.82	$ 27.98
2026	18,784	11,740	7,044	$ 25.39	$ 31.04	$ 298,115.79	$ 218,631.58	$ 516,747.37	$ 27.51
2027	18,643	10,574	8,068	$ 25.45	$ 32.10	$ 269,091.11	$ 258,992.81	$ 528,083.92	$ 28.33
2028	18,502	10,417	8,085	$ 27.95	$ 32.04	$ 291,117.79	$ 259,038.51	$ 550,156.30	$ 29.74
2029	18,363	8,077	10,286	$ 32.30	$ 31.89	$ 260,879.36	$ 328,019.37	$ 588,898.73	$ 32.07
2030	18,227	8,100	10,127	$ 32.24	$ 33.01	$ 261,141.12	$ 334,292.07	$ 595,433.19	$ 32.67
2031	18,090	7,593	10,497	$ 33.61	$ 33.19	$ 255,177.31	$ 348,351.69	$ 603,529.00	$ 33.36
2032	17,953	7,430	10,523	$ 34.55	$ 34.39	$ 256,711.95	$ 361,943.64	$ 618,655.59	$ 34.46
2033	17,820	7,079	10,741	$ 34.28	$ 34.83	$ 242,676.13	$ 374,097.98	$ 616,774.12	$ 34.61
2034	17,686	6,348	11,338	$ 34.34	$ 35.59	$ 217,961.18	$ 403,498.45	$ 621,459.63	$ 35.14
2035	17,554	6,187	11,367	$ 35.11	$ 35.96	$ 217,207.20	$ 408,796.44	$ 626,003.64	$ 35.66
2036	17,422	5,709	11,713	$ 35.19	$ 37.22	$ 200,884.80	$ 435,984.41	$ 636,869.20	$ 36.56
2037	17,290	5,177	12,113	$ 36.46	$ 37.72	$ 188,785.42	$ 456,832.75	$ 645,618.17	$ 37.34
2038	17,161	4,905	12,256	$ 36.73	$ 38.17	$ 180,189.92	$ 467,828.30	$ 648,018.22	$ 37.76
2039	17,034	4,844	12,190	$ 37.32	$ 39.61	$ 180,761.97	$ 482,786.30	$ 663,548.27	$ 38.95
2040	16,905	4,543	12,361	$ 39.09	$ 40.42	$ 177,598.22	$ 499,590.11	$ 677,188.33	$ 40.06
2041	16,776	4,308	12,468	$ 39.81	$ 41.61	$ 171,499.18	$ 518,795.00	$ 690,294.17	$ 41.15
2042	16,653	4,014	12,639	$ 40.05	$ 42.93	$ 160,772.52	$ 542,599.41	$ 703,371.93	$ 42.24

WACC 7.03% nominal, annual

Summary: NPV and Annualized $/MWh of Energy Avoided Costs, WITHOUT Carbon Price Impact

NPV Of Energy Costs	$ 300.96	$/MWh
Levelized Payment	$ 25.89	$/MWh

Summary Table: Annual Hydro QF Generation and Energy Avoided Costs WITHOUT Carbon Price Impacts

Year	Generation (MWh)	Offset Generation (MWh)	Offset Purchases (MWh)	Average Offset Generation Price ($/MWh)	Average Offset Purchase Price ($/MWh)	Total Offset Generation Energy Avoided Cost ($)	Total Energy Avoided Cost of Purchases ($)	Total Energy Avoided Cost ($)	Average Energy Avoided Cost ($/MWh)
2018	54,754	23,577	31,177	$ 10.99	$ 21.55	$ 259,181.67	$ 671,737.69	$ 930,919.35	$ 17.00
2019	54,754	23,074	31,680	$ 11.32	$ 22.23	$ 261,174.50	$ 704,364.29	$ 965,538.79	$ 17.63
2020	54,754	24,371	30,383	$ 12.82	$ 25.60	$ 312,562.26	$ 777,724.03	$ 1,090,286.29	$ 19.91
2021	54,754	25,146	29,608	$ 12.10	$ 25.79	$ 304,253.67	$ 763,556.65	$ 1,067,810.32	$ 19.50
2022	54,754	20,871	33,883	$ 12.38	$ 25.42	$ 258,413.20	$ 861,433.81	$ 1,119,847.01	$ 20.45
2023	54,754	22,209	32,545	$ 14.51	$ 28.58	$ 322,326.99	$ 930,277.88	$ 1,252,604.88	$ 22.88
2024	54,754	21,782	32,972	$ 10.41	$ 31.46	$ 226,729.96	$ 1,037,312.07	$ 1,264,042.04	$ 23.09
2025	54,754	37,098	17,656	$ 24.25	$ 29.90	$ 899,734.43	$ 527,993.05	$ 1,427,727.47	$ 26.08
2026	54,754	36,157	18,597	$ 23.90	$ 29.48	$ 864,076.35	$ 548,279.20	$ 1,412,355.55	$ 25.79
2027	54,754	32,113	22,641	$ 24.06	$ 30.48	$ 772,500.47	$ 690,205.97	$ 1,462,706.44	$ 26.71
2028	54,754	31,791	22,964	$ 26.09	$ 30.46	$ 829,545.15	$ 699,554.69	$ 1,529,099.84	$ 27.93
2029	54,754	27,084	27,670	$ 29.49	$ 29.94	$ 798,848.61	$ 828,332.55	$ 1,627,181.17	$ 29.72
2030	54,754	26,902	27,852	$ 29.70	$ 30.98	$ 798,994.58	$ 862,749.22	$ 1,661,743.80	$ 30.35
2031	54,754	25,565	29,189	$ 30.83	$ 31.19	$ 788,205.58	$ 910,362.95	$ 1,698,568.53	$ 31.02
2032	54,754	25,248	29,506	$ 31.81	$ 32.15	$ 803,051.55	$ 948,658.38	$ 1,751,709.93	$ 31.99
2033	54,754	23,981	30,773	$ 31.84	$ 32.69	$ 763,624.89	$ 1,006,016.90	$ 1,769,641.79	$ 32.32
2034	54,754	21,954	32,800	$ 32.28	$ 33.55	$ 708,683.86	$ 1,100,264.97	$ 1,808,948.83	$ 33.04
2035	54,754	21,407	33,347	$ 33.02	$ 33.90	$ 706,791.65	$ 1,130,477.60	$ 1,837,269.25	$ 33.55
2036	54,754	20,102	34,652	$ 33.44	$ 35.02	$ 672,319.26	$ 1,213,497.01	$ 1,885,816.28	$ 34.44
2037	54,754	18,432	36,322	$ 34.37	$ 35.51	$ 633,518.59	$ 1,289,861.05	$ 1,923,379.63	$ 35.13
2038	54,754	17,444	37,310	$ 34.62	$ 35.99	$ 603,825.89	$ 1,342,637.53	$ 1,946,463.43	$ 35.55
2039	54,754	17,373	37,381	$ 35.46	$ 37.39	$ 616,115.06	$ 1,397,652.99	$ 2,013,768.05	$ 36.78
2040	54,754	16,835	37,920	$ 36.90	$ 38.16	$ 621,131.72	$ 1,447,168.22	$ 2,068,299.94	$ 37.77
2041	54,754	15,438	39,316	$ 37.64	$ 39.40	$ 581,167.82	$ 1,548,927.58	$ 2,130,095.40	$ 38.90
2042	54,754	14,856	39,898	$ 38.28	$ 40.53	$ 568,669.64	$ 1,617,175.20	$ 2,185,844.84	$ 39.92

Summary: NPV and Annualized $/MWh of Energy Avoided Costs, WITH Carbon Price Impact

NPV Of Energy Costs	$	453.74	$/MWh
Levelized Payment	$	39.04	$/MWh

Summary Table: Annual Wind QF Generation and Energy Avoided Costs WITH Carbon Price Impacts

Year	Generation (MWh)	Offset Generation (MWh)	Offset Purchases (MWh)	Average Offset Generation Price ($/MWh)	Average Offset Purchase Price ($/MWh)	Total Offset Generation Energy Avoided Cost ($)	Total Energy Avoided Cost of Purchases ($)	Total Energy Avoided Cost ($)	Average Energy Avoided Cost ($/MWh)
2018	39,471	17,372	22,099	$ 11.61	$ 22.85	$ 201,717.60	$ 504,928.50	$ 706,646.10	$ 17.90
2019	39,471	17,472	21,999	$ 12.28	$ 23.62	$ 214,539.02	$ 519,705.01	$ 734,244.03	$ 18.60
2020	39,471	18,299	21,172	$ 13.67	$ 27.12	$ 250,080.96	$ 574,150.53	$ 824,231.49	$ 20.88
2021	39,471	18,551	20,920	$ 13.19	$ 27.22	$ 244,716.98	$ 569,510.76	$ 814,227.73	$ 20.63
2022	39,471	16,145	23,326	$ 21.61	$ 39.07	$ 348,977.45	$ 911,284.77	$ 1,260,262.22	$ 31.93
2023	39,471	17,140	22,331	$ 23.14	$ 42.90	$ 396,582.47	$ 957,881.16	$ 1,354,463.63	$ 34.32
2024	39,471	16,418	23,054	$ 28.91	$ 46.24	$ 474,647.67	$ 1,066,023.21	$ 1,540,670.87	$ 39.03
2025	39,471	27,941	11,530	$ 38.35	$ 46.21	$ 1,071,586.34	$ 532,831.80	$ 1,604,418.15	$ 40.65
2026	39,471	27,333	12,138	$ 39.12	$ 46.26	$ 1,069,244.47	$ 561,548.31	$ 1,630,792.78	$ 41.32
2027	39,471	23,785	15,686	$ 39.73	$ 47.77	$ 944,962.35	$ 749,339.19	$ 1,694,301.54	$ 42.93
2028	39,471	23,964	15,507	$ 41.91	$ 48.54	$ 1,004,440.07	$ 752,652.62	$ 1,757,092.69	$ 44.52
2029	39,471	22,282	17,189	$ 46.38	$ 48.39	$ 1,033,398.64	$ 831,758.86	$ 1,865,157.50	$ 47.25
2030	39,471	21,898	17,573	$ 47.26	$ 50.13	$ 1,034,864.51	$ 880,866.97	$ 1,915,731.48	$ 48.54
2031	39,471	21,169	18,302	$ 48.18	$ 51.10	$ 1,020,015.17	$ 935,302.55	$ 1,955,317.72	$ 49.54
2032	39,471	20,927	18,544	$ 50.29	$ 52.85	$ 1,052,448.56	$ 980,010.04	$ 2,032,458.60	$ 51.49
2033	39,471	20,021	19,450	$ 51.04	$ 54.17	$ 1,021,877.80	$ 1,053,670.35	$ 2,075,548.15	$ 52.58
2034	39,425	18,365	21,060	$ 52.66	$ 55.82	$ 967,050.59	$ 1,175,614.96	$ 2,142,665.55	$ 54.35
2035	39,471	17,968	21,503	$ 54.47	$ 57.05	$ 978,671.16	$ 1,226,735.50	$ 2,205,406.66	$ 55.87
2036	39,471	16,869	22,602	$ 55.82	$ 58.99	$ 941,606.17	$ 1,333,326.02	$ 2,274,932.19	$ 57.64
2037	39,471	15,409	24,062	$ 57.44	$ 60.42	$ 885,022.97	$ 1,453,736.47	$ 2,338,759.44	$ 59.25
2038	39,471	14,665	24,806	$ 58.57	$ 61.79	$ 858,835.82	$ 1,532,905.79	$ 2,391,741.60	$ 60.59
2039	39,471	14,477	24,994	$ 61.35	$ 64.32	$ 888,082.28	$ 1,607,574.95	$ 2,495,657.23	$ 63.23
2040	39,471	14,213	25,258	$ 63.50	$ 66.13	$ 902,504.20	$ 1,670,198.94	$ 2,572,703.14	$ 65.18
2041	39,291	12,834	26,456	$ 64.93	$ 68.38	$ 833,307.52	$ 1,809,152.07	$ 2,642,459.60	$ 67.25
2042	39,292	12,325	26,967	$ 66.65	$ 70.64	$ 821,467.71	$ 1,904,968.43	$ 2,726,436.14	$ 69.39

Summary: NPV and Annualized $/MWh of Energy Avoided Costs, WITH Carbon Price Impact

NPV Of Energy Costs	$	456.40	$/MWh
Levelized Payment	$	39.27	$/MWh

Summary Table: Annual Solar QF Generation and Energy Avoided Costs WITH Carbon Price Impacts

Year	Generation (MWh)	Offset Generation (MWh)	Offset Purchases (MWh)	Average Offset Generation Price ($/MWh)	Average Offset Purchase Price ($/MWh)	Total Offset Generation Energy Avoided Cost ($)	Total Energy Avoided Cost of Purchases ($)	Total Energy Avoided Cost ($)	Average Energy Avoided Cost ($/MWh)
2018	19,947	6,672	13,275	11.818111	$ 22.31	$ 78,847.98	$ 296,170.89	$ 375,018.86	$ 18.80
2019	19,800	6,421	13,379	12.539291	$ 23.04	$ 80,514.68	$ 308,305.07	$ 388,819.75	$ 19.64
2020	19,652	6,682	12,970	14.312817	$ 26.43	$ 95,639.25	$ 342,816.97	$ 438,456.22	$ 22.31
2021	19,503	7,214	12,289	13.447198	$ 26.71	$ 97,006.74	$ 328,206.69	$ 425,213.43	$ 21.80
2022	19,359	5,615	13,744	17.515627	$ 38.40	$ 98,346.86	$ 527,797.49	$ 626,144.35	$ 32.34
2023	19,212	5,919	13,293	19.097123	$ 42.16	$ 113,042.33	$ 560,445.16	$ 673,487.49	$ 35.06
2024	19,068	5,919	13,149	21.559581	$ 45.71	$ 127,601.17	$ 601,022.86	$ 728,624.03	$ 38.21
2025	18,925	12,069	6,856	38.218483	$ 45.04	$ 461,256.39	$ 308,798.88	$ 770,055.27	$ 40.69
2026	18,784	11,740	7,044	38.748958	$ 45.16	$ 454,903.49	$ 318,080.67	$ 772,984.16	$ 41.15
2027	18,643	10,574	8,068	39.23679	$ 46.81	$ 414,909.16	$ 377,646.80	$ 792,555.97	$ 42.51
2028	18,502	10,417	8,085	41.304829	$ 47.36	$ 430,266.22	$ 382,885.32	$ 813,151.54	$ 43.95
2029	18,363	8,077	10,286	47.354016	$ 47.84	$ 382,455.53	$ 492,128.43	$ 874,583.96	$ 47.63
2030	18,227	8,100	10,127	47.87752	$ 49.62	$ 387,803.16	$ 502,542.04	$ 890,345.20	$ 48.85
2031	18,090	7,593	10,497	48.108035	$ 50.49	$ 365,271.67	$ 529,994.58	$ 895,266.24	$ 49.49
2032	17,953	7,430	10,523	51.326117	$ 52.41	$ 381,331.62	$ 551,552.78	$ 932,884.40	$ 51.96
2033	17,820	7,079	10,741	50.365968	$ 53.60	$ 356,548.21	$ 575,709.55	$ 932,257.76	$ 52.32
2034	17,686	6,348	11,338	52.155322	$ 55.14	$ 331,060.40	$ 625,139.80	$ 956,200.20	$ 54.07
2035	17,554	6,187	11,367	53.832831	$ 56.32	$ 333,058.85	$ 640,208.78	$ 973,267.62	$ 55.44
2036	17,422	5,709	11,713	54.671113	$ 58.45	$ 312,115.32	$ 684,570.72	$ 996,686.04	$ 57.21
2037	17,290	5,177	12,113	56.471144	$ 59.80	$ 292,371.55	$ 724,350.23	$ 1,016,721.78	$ 58.80
2038	17,161	4,905	12,256	57.568294	$ 61.17	$ 282,383.32	$ 749,685.20	$ 1,032,068.52	$ 60.14
2039	17,034	4,844	12,190	59.227617	$ 63.56	$ 286,895.35	$ 774,760.09	$ 1,061,655.44	$ 62.33
2040	16,905	4,543	12,361	62.039764	$ 65.36	$ 281,874.49	$ 807,983.68	$ 1,089,858.18	$ 64.47
2041	16,776	4,308	12,468	62.824416	$ 67.60	$ 270,624.65	$ 842,795.47	$ 1,113,420.12	$ 66.37
2042	16,653	4,014	12,639	63.947113	$ 69.99	$ 256,671.65	$ 884,613.08	$ 1,141,284.74	$ 68.53

Summary: NPV and Annualized $/MWh of Energy Avoided Costs, WITH Carbon Price Impact

NPV Of Energy Costs	$	430.33	$/MWh
Levelized Payment	$	37.03	$/MWh

Summary Table: Annual Hydro QF Generation and Energy Avoided Costs WITH Carbon Price Impacts

Year	Generation (MWh)	Offset Generation (MWh)	Offset Purchases (MWh)	Average Offset Generation Price ($/MWh)	Average Offset Purchase Price ($/MWh)	Total Offset Generation Energy Avoided Cost ($)	Total Energy Avoided Cost of Purchases ($)	Total Energy Avoided Cost ($)	Average Energy Avoided Cost ($/MWh)
2018	54,754	23,577	31,177	$ 10.99	$ 21.55	$ 259,181.67	$ 671,737.69	$ 930,919.35	$ 17.00
2019	54,754	23,074	31,680	$ 11.32	$ 22.23	$ 261,174.50	$ 704,364.29	$ 965,538.79	$ 17.63
2020	54,754	24,371	30,383	$ 12.82	$ 25.60	$ 312,562.26	$ 777,724.03	$ 1,090,286.29	$ 19.91
2021	54,754	25,146	29,608	$ 12.10	$ 25.79	$ 304,253.67	$ 763,556.65	$ 1,067,810.32	$ 19.50
2022	54,754	20,871	33,883	$ 16.61	$ 37.42	$ 346,589.29	$ 1,268,026.41	$ 1,614,615.69	$ 29.49
2023	54,754	22,209	32,545	$ 17.77	$ 41.08	$ 394,655.22	$ 1,337,029.09	$ 1,731,684.31	$ 31.63
2024	54,754	21,782	32,972	$ 22.83	$ 44.47	$ 497,362.85	$ 1,466,407.70	$ 1,963,770.55	$ 35.87
2025	54,754	37,098	17,656	$ 35.61	$ 43.46	$ 1,321,072.72	$ 767,308.60	$ 2,088,381.32	$ 38.14
2026	54,754	36,157	18,597	$ 36.28	$ 43.60	$ 1,311,591.30	$ 810,837.11	$ 2,122,428.41	$ 38.76
2027	54,754	32,113	22,641	$ 36.80	$ 45.19	$ 1,181,823.50	$ 1,023,166.00	$ 2,204,989.50	$ 40.27
2028	54,754	31,791	22,964	$ 39.14	$ 45.78	$ 1,244,203.17	$ 1,051,309.67	$ 2,295,512.84	$ 41.92
2029	54,754	27,084	27,670	$ 45.00	$ 45.89	$ 1,218,812.58	$ 1,269,778.70	$ 2,488,591.27	$ 45.45
2030	54,754	26,902	27,852	$ 45.58	$ 47.59	$ 1,226,080.91	$ 1,325,487.42	$ 2,551,568.33	$ 46.60
2031	54,754	25,565	29,189	$ 46.32	$ 48.49	$ 1,184,270.75	$ 1,415,446.50	$ 2,599,717.25	$ 47.48
2032	54,754	25,248	29,506	$ 48.76	$ 50.17	$ 1,230,947.63	$ 1,480,304.35	$ 2,711,251.98	$ 49.52
2033	54,754	23,981	30,773	$ 49.07	$ 51.46	$ 1,176,812.86	$ 1,583,649.92	$ 2,760,462.78	$ 50.42
2034	54,754	21,954	32,800	$ 50.82	$ 53.09	$ 1,115,645.36	$ 1,741,432.82	$ 2,857,078.18	$ 52.18
2035	54,754	21,407	33,347	$ 52.57	$ 54.26	$ 1,125,305.25	$ 1,809,367.63	$ 2,934,672.89	$ 53.60
2036	54,754	20,102	34,652	$ 53.71	$ 56.24	$ 1,079,657.23	$ 1,948,924.52	$ 3,028,581.75	$ 55.31
2037	54,754	18,432	36,322	$ 55.44	$ 57.60	$ 1,021,834.26	$ 2,092,063.90	$ 3,113,898.16	$ 56.87
2038	54,754	17,444	37,310	$ 56.44	$ 58.98	$ 984,518.88	$ 2,200,691.05	$ 3,185,209.93	$ 58.17
2039	54,754	17,373	37,381	$ 58.86	$ 61.34	$ 1,022,621.86	$ 2,293,014.37	$ 3,315,636.23	$ 60.56
2040	54,754	16,835	37,920	$ 61.50	$ 63.11	$ 1,035,334.24	$ 2,393,190.44	$ 3,428,524.68	$ 62.62
2041	54,754	15,438	39,316	$ 62.73	$ 65.38	$ 968,456.24	$ 2,570,586.22	$ 3,539,042.46	$ 64.64
2042	54,754	14,856	39,898	$ 64.19	$ 67.59	$ 953,513.01	$ 2,696,823.85	$ 3,650,336.86	$ 66.67

PREFILED REBUTTAL TESTIMONY

OF BLEAU J. LAFAVE

ON BEHALF OF NORTHWESTERN ENERGY

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Witness Information

Q. Please state your name and business address.

A. My name is Bleau J. LaFave. My business address is 3010 West 69th Street, Sioux Falls, South Dakota 57108.

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

A. I am NorthWestern Energy's ("NorthWestern") Director of Long Term Resources.

Q. Are you the same Bleau J. LaFave who submitted prefiled additional issues testimony in this docket?

A. Yes.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to rebut claims made by Vote Solar and Montana Environmental Information Center witness R. Thomas Beach in his pre-filed direct testimony concerning the avoided cost, methods, hedging, price mitigation, Qualifying Facility ("QF") success rates, and effects on customers.

Rebuttal of Pre-filed Direct Testimony of R. Thomas Beach

Q. Do you agree with Mr. Beach that the price for power from a QF should equal 100% of avoided cost?

A. Yes, but it is critically important to clarify that the calculated avoided cost is the avoided cost of NorthWestern **to serve its load**: "[T]he purchase rate should only include payment for energy or capacity which the utility can use to meet its total system load." Federal Energy Regulatory Commission ("FERC") Order 69 explaining FERC rule 18 CFR § 292.303. The ratepayer neutrality required by federal law can only be provided through a correct application of the avoided cost standard. Avoided costs are the incremental costs of serving load saved by purchasing power from a QF:

> If, by purchasing electric energy from a qualifying facility, a utility can reduce its energy costs or can avoid purchasing from another utility, the rate for purchase from a qualifying facility is to be based on those energy costs which the utility can thereby avoid…The Commission has added the term "incremental" to modify the costs which an electric utility would avoid as a result of making a purchase from a qualifying facility. Under the principles of economic dispatch, utilities generally turn on last and turn off first their generating units with the highest running costs. At any given time, an economically dispatched utility can avoid operating its highest-cost units as a result of making a purchase from a qualifying facility. The utility's avoided incremental costs (and not average system costs) should be used to calculate the avoided cost."

FERC Order 69 explaining the definitions in its rule 18 CFR §292.101.

Energy purchases and the cost of native generation are the costs incurred by NorthWestern to meet its load service obligation. When NorthWestern is long on energy and sells into the market, it is not avoiding costs. It is generating revenues which are credited to its ratepayers through the ratemaking process. The Public Utility Regulatory Policies Act was not intended as a means to force NorthWestern to broker power for QF developers at the expense and risk of its retail customers.

Q. Is there another jurisdiction that assigns a zero avoided cost value when a utility's internal generation is at a must-run condition and the load is less than the amount generated by the portfolio?

A. Yes. In Idaho in Case No. GNR-E-11-03, the Idaho Public Utilities Commission ("PUC") approved a value of zero during hours that Idaho Power Company's load was less than the must-run (minimum dispatch) levels as identified by Idaho Power Company witness Karl Bokenkamp in his Direct Testimony.

Q. On page 17, line 14, Mr. Beach contends that NorthWestern is using a fundamentally new method of calculating the avoided costs for standard rate contracts. Do you agree with his assessment?

A. Yes. NorthWestern is using a different method for calculating the avoided costs for standard rate contracts. However, production cost modeling is hardly a new concept. NorthWestern has used PowerSimm™ in the last two planning cycles for planning purposes as well as for evaluating QFs, Community Renewable Energy Projects, and owned resources. It provides a platform for resource evaluation which can account for the dynamic nature of NorthWestern's loads, the market, and its changing resource portfolio. Other methods like the Proxy Method, Blended Market Method, and Peaker Method provide rough estimates of avoided cost that can be used, in appropriate specific conditions. However, such high-level estimates should not be used when a production cost model is available.

A production cost model is much more accurate and provides cost estimates based on actual production assets and power purchase agreements ("PPA") specific to the customer load. As an example, in Idaho in Case No. GNR-E-11-03, the Idaho PUC approved the use of a production cost model for non-standard contracts. The Montana Public Service Commission ("Commission") also approved Montana-Dakota Utilities' ("MDU") avoided cost standard rate in Docket No. D2015.7.59, Order No. 7450a that was based on MDU's production cost model.

Q. Do you agree with Mr. Beach starting on page 29, line 11 that these solar facilities will provide a fixed-price hedge against future uncertainty and volatility in energy and fossil fuel markets?

A. It is true that a fixed-price contract, by definition, reduces price volatility, by calling out a price. However, the real certainty arising from the calculation of a levelized fixed price using long-term price forecasts is that the realized market price will deviate from the levelized fixed price due to forecasting error. A just and reasonable avoided cost calculation does not sacrifice accuracy for certainty.

Q. Is there an additional value that should be added to the avoided costs for any possible hedging benefit?

A. No. Hedging benefits are not an avoided cost and should not be included in the calculation of avoided costs. Moreover, a fixed price for an intermittent resource really does not provide much certainty, as there is no certainty associated with the delivery of the power, which is an integral part of a real hedge.

Q. Do you agree with Mr. Beach starting on page 32, line 19 that solar facilities will provide market price mitigation because of the zero variable costs?

A. Yes, if power from solar facilities becomes a significant part of the portfolios of the many utilities in the region, this could have downward pressure on certain hours of the market forecast. This effect would also reduce the avoided costs for the utilities. NorthWestern believes these expected effects are reflected in the Intercontinental Exchange market forecast for Mid-C and the annual Energy Information Administration forecasts. NorthWestern's production cost model also assumes a zero variable cost for such resources so that the value is already included in the avoided cost calculation. Inclusion of additional value would result in an avoided cost that would prevent NorthWestern's customers from taking advantage of market conditions that are attributable to solar projects connected to other utilities in the region and increase the risk that NorthWestern's contracts would be above market thereby eliminating the benefit that Mr. Beach is discussing.

Q. Do you agree with Mr. Beach starting on page 39 that there will be a relatively low rate of success for QF solar projects at the current QF-1 rate?

A. No. The current QF-1 rate is significantly over market. As was obvious to the Commission in this docket, the current QF-1 rates attracted a significant number of solar QFs intending to take advantage of the existing rate. Typically, large companies that are created specifically to build these types of projects will have success rates for completing projects that are much higher than individual small companies working on single projects. Most of the projects proposed to NorthWestern were being developed by three companies. The reason only nine PPAs were signed is that the Commission stayed the current standard rate for projects over 100 kilowatts.

Q. Do you agree with Mr. Beach starting on page 40 that if only 25 PPAs equaling 75 megawatts were successful at the current rates it would be a benefit to NorthWestern customers?

A. No. As stated in the Prefiled Direct Testimony of John D. Hines earlier in this docket, these contracts would be over $5 million out of market each. Customers would pay over $125 million more than they should have based on the market price.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

CERTIFICATE OF SERVICE

I hereby certify that the original and 10 copies of NorthWestern Energy's Rebuttal Testimony in Docket No. D2016.5.39, the QF-1 Avoided Cost Rate Filing, have been hand-delivered to the Montana Public Service Commission with three copies to the Montana Consumer Counsel this date. It has also been e-filed on the Commission website, emailed to counsel of record, and sent via First Class Mail to the attached service list.

Date: December 12, 2016

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