Before the New Hampshire
Public Utilities Commission

DE 18-____

Motion to Correct Errors in PUC Determination of Avoided Costs

March 1, 2018

Now comes Clifton Below, a customer-generator with Granite State Electric Company, d.b.a. Liberty Utilities (LU), with a home address of 25 Perley Avenue, Lebanon, NH 03766-1816 and an email address of clifton.below@gmail.com and moves that the Commission correct errors in its determination of avoided costs pursuant to Puc 903.02(j) and revise its determination of rates for avoided energy costs and capacity factors as necessary. I state the following, all true to the best of my knowledge and belief, in support of this motion:

1. Puc 903.02(j) reads as follows: "To correct an error in its determination of avoided costs, the commission shall, on its own motion, the motion of a utility, or the motion of a third party revise its determination of rates for avoided costs and capacity factors as necessary. Any amounts paid or credited at the originally published rates and capacity factors shall be subject to reconciliation by the revised rates and factors."

2. The annual commission determinations of avoided costs in Puc 903.02(i) are for the purposes of "determining the rates for utility avoided costs for energy and capacity consistent with the requirements of the Public Utilities Regulatory Policy Act of 1978 (PURPA) (16 USC § 824a-3 and 18 CFR § 292.304)" and RSA 362-A:9 V(b).

3. Puc 903.02(i)(7) provides that (with emphasis added):

> (7) For net metered PV systems for which actual hourly data is not utilized pursuant to (5) above, the rate for avoided energy costs shall be calculated as a weighted average annual rate by weighting the actual avoided costs for each hour of the 12 months ending the immediately preceding March 31 by the hourly generation output profile for PV systems in New Hampshire determined as follows:

a**. If verifiable hourly generation output data is available and on file at the commission by April 5 for the applicable year from at least 25 kW of PV system capacity operating within New Hampshire, then the output profile for PV systems shall be the hourly average of all such data;** or

b. If such data is not available the hourly generation output profile shall be the modeled hourly PV performance data output produced by the U.S. Department of Energy, National Renewable Energy Laboratory, PVWatts software, version 1, (available at http://www.nrel.gov/rredc/pvwatts/site_specific.html) with the default settings for Concord, New Hampshire; and

c. The portion of surplus generation estimated to be produced during the hour or hours of capacity peak on which FCM costs are allocated to load shall be in the same proportion as the output profile utilized pursuant to (7) a. or b. above.

4. In May of 2017 I received a letter from Liberty Utilities advising that I had an accumulated surplus of electricity of 9,942 kWh with an economic value of $0.04594/kWh for a total of $456.71 for avoided energy and capacity costs. (Attachment p. 7.) I have no issue with LU's calculation of this value as it is consistent with the avoided cost values for PV systems published in an Excel spreadsheet on the PUC website at this address: www.puc.nh.gov/Electric/Avoided%20Cost%20Calculation%20for%20Puc%20900%204-20-2017_Final%20version.xlsx ("2017 Source Spreadsheet"). On Attachment p. 8 I have provided a copy of the first tab of 2017 Source Spreadsheet, supplemented by the area within the box to include a calculator that coverts the percent of production of both solar and non-solar generation on system peak for capacity value purposes into a value per kWh and sums that with the energy services value per kWh to generate a total avoided cost value for PV of $0.04594/kWh for PV and $0.03767/kWh for Non-PV. There is also a calculator that allows input in the yellow square to calculate the value of a specific amount of surplus PV production. I've shown my case with 9,942 kWh resulting in a value of $456.71, which exactly matches the value of Liberty's calculation.

5. Upon recent examination of the source spreadsheet I identified one material error that I believe should be corrected. The error results in an undervaluation of the avoided costs for net metered

solar generation of approximately 8.9% resulting in a benefit shift from customer-generators to others.

6. The apparent error arises from the first use of actual hourly generation output data as provided for in Puc 903.02(i)(7)a, instead of modeled data as provided for in Puc 903.02(i)(7)b, as has been used in past years for this calculation. The actual data apparently came with time stamps that started each day with the hour "0:00" and ended with an hourly time stamp of "23:00." This source data apparently used an interval beginning convention or "hour beginning" format but was incorrectly assumed to be in an "hour ending" format. Hence, cell N:10 of the 2017 Source Spreadsheet in the "Actual Solar Data" tab has a note that states, regarding the line of data with a date and time stamp of "4/1/2016 0:00": "Did not use. Started with Hour ending 1 am". (See p. 9). Hence, when the average production data from the "Actual Solar Data" tab was transferred to the "AC Calc" tab it was all shifted by an hour earlier than actual due to conflating "hour beginning" with "hour ending."

7. Compelling evidence for the error can be found by comparing production during the hour of sunrise with the hour of sunset, the hour before the hour of sunrise with the hour after the hour of sunset, as well as the hour and 2nd hour after the hour of sunrise with the hour and 2nd hour before the hour of sunset. Some symmetry in average PV production across multiple systems and dates between these matching pairs of hours relative to sunrise and sunset should be expected due to the nature of solar insolation and PV technology. On Attachment pp. 9-12 I show the "Original" results for 16 dates[1] after taking the "Actual Solar Data" tab from the 2017 Source Spreadsheet and noting the time of sunrise and sunset in a new column N in the same row as the hour of sunrise and sunset, respectively,[2] assuming the original time stamp in column A is for hour ending, as staff apparently

[1] In 2016: 4/1, 4/15, 5/1, 6/1, 8/1, 9/1, 9/21-equinox, 11/5-last full day of DST, 11/6-day that DST ended, and 12/16; and for 2017: 1/1, 2/1, 3/1, 3/11-last day before DST begins, 3/12-first day of DST, and 3/31,

[2] The ratios in column O and the highlighting were also added to aid in these comparisons. Extraneous columns and rows are hidden for presentation purposes and some notes and titles were added in RED.

did. The results are telling. For 15 of the 16 dates,[3] one or more of the 8 systems for which data is used show production during the hour before the hour of sunrise (even when sunrise is a half hour or more into the hour of sunrise) and no systems report any production during the hour after the hour of sunset. **Furthermore, not a single system shows any production during the hour of sunset** (even when sunset is last third of that hour, such as on 5/1, 9/21, 2/1, 3/11 and 3/12). In addition, there are typically very high ratios of production during the hour after the hour of sunrise compared with the hour before hour of sunset, such as 849 to 1 on 4/1/16. There are also typically high ratios for the 2nd hour after the hour of sunrise compared with the 2nd hour before sunset.

8. On Attachment pp. 13-16 I show the results for the 16 examined dates where I simple shifted all of production data down one row relative to the time stamps, so the data is treated it as if it was originally date stamped with "hour beginning" but aligns with the times in Column A as if they continue to be "hour ending." This result should be conclusive as to the nature of the original error and the correction needed. With this one-hour shift, NONE of the 8 systems on any of the 16 dates (128 data points) show any production during either the hour before the hour of sunrise or during the hour after the hour of sunset, as is to be expected with **SOLAR** PV. Furthermore on 9 of the 16 dates examined the ratio of the average production during the hour after the hour of sunrise to the average production during hour before the hour of sunset is actually 1 to 1 (to one significant digit) and all the other ratios are much closer to 1:1 than in the analysis of how the data was originally treated. Likewise, 7 of 16 ratios of production from the 2nd hour after sunrise to the 2nd hour before

[3] The exception is 12/1/16 when sunrise was at 6:59 am, so very little if any production should be expected even in the hour of sunrise, though all 8 systems show significant production within a minute or so of sunrise on that date, including the system in Keene where sunrise and sunset typically lags 3-4 minutes behind Concord. In Stratham and Rochester sunrise and sunset are typically 2-3 minutes earlier than Concord, while sunrise and sunset of the other locations of the identified systems are usually within a minute or two of Concord. The U.S. Naval Observatory website was the source of the sunrise and sunset times for Concord and each of the other identified system locations I examined for this analysis: http://aa.usno.navy.mil/data/docs/RS_OneYear.php.

sunset are reduced to 1:1, while all the others are closer than before. Note that 2/1/17 and 3/31/17 both generate anomalies in these ratios due to noted weather conditions.[4]

9. The result of using the actual PV data with correct time stamps is shown on Attachment p. 17, which includes the supplemental boxed area that converts the avoided capacity value to $/kWh. As both the energy value/kWh increases (from $33.31/MWh to $34.90/MWh) and capacity value increases (from $12.63/MWh to $15.21/MWh), the total avoided cost value for PV system surpluses increases from $0.04594/kWh to $0.05011/kWh, an 8.9% increase. The corrected result for my 2017 accumulated surplus of 9,942 kWh is shown in the boxed calculator.

10. I observed this problem with inconsistency in how solar PV production is time stamped when I was analyzing data from different systems and different vendors during pre-hearing stages of DE 16-576, so I've noticed that daily time series that start with hour 0:00 and end with 23:00 seem to be using an hour beginning convention while daily time series that start with hour 01:00 and end with 24:00 seem to use an hour ending convention. I also note that ISO New England, while continuing to publish hourly market data using the interval ending convention, is now using the interval beginning convention for sub-hourly interval settlements.[5]

11. Properly adjusting for transitions in and out of Daylight Savings Time (DST) can also be a problem but was done correctly in both the 2017 Source Spreadsheet and my correction shown herein; in both cases by tweaking the formula in the "AC Calc" tab at the end and start of DST. For future clarity and to reduce the chance of error, it might be worth making the adjustment in the actual PV data set such that there is a 25 hour day on the November date that DST ends (with the extra hour

[4] On 2/1/17 it snowed in the morning followed by melting temperatures in the afternoon resulting in high production before sunset compared with after sunrise and on 3/31/17 it snowed in the afternoon and evening resulting in comparatively high production after sunrise compared with late afternoon approaching sunset.

[5] See, for example, p. 17 of this document: https://www.iso-ne.com/static-assets/documents/2016/12/2016q4_sif_presentation.pdf

labeled 2X, as ISO-NE does) and a 23 hour day on the March date that DST begins (with the hour ending 2 am skipped), rather than having to customize the formulas deep inside the "AC Calc" tab each year. Comparing such results with actual sunrise and sunset can help flag any potential errors.

12. Finally, I also note that the simple average of the azimuth of the 8 systems used for the 2017 calculation is 161.1°, which is nearly 19° east of due south (as shown on Attachment p.7, cell K:7). Puc 900 is silent on the azimuth and tilt of actual systems used for calculating avoided costs, although the modeled optimal system uses an azimuth of 180° (due south). In my direct testimony in DE 16-576 I analyzed available data for actual PV systems and found that those that are more western oriented (azimuth of >180°) or tracking on average produced at higher average value hours (energy and capacity) than more eastern oriented systems (see for example Schedule CCB-1)[6]. This is logical due to summer system peaks occurring in the afternoon, and hence LMPs are typically higher in the afternoon than in the morning and the basis for capacity charges is also in the afternoon. I did do a calculation of the capacity weighted average of the azimuth of the 8 systems used and found that to be 167.08°, which is nearly 13° east of due south, which is better than the simple average of 19° east of due south. This is shown at cell M:8800 on Attachment p. 12. Although not required, it would be a good practice to try and use actual data from systems that have a capacity weighted average azimuth of closer to 180°, which is presumably the average azimuth of installed systems in a regulatory framework where there are no temporal value signals in net metering tariffs. In order to maximize annual production and value, all other things being equal (such as shading and roof orientation), installers would tend to target an azimuth of 180° as optimal.

/s/ Clifton C. Below

[6] Found at lines 13, 17, and 26-28 of Bates stamped page 28 at: https://www.puc.nh.gov/Regulatory/Docketbk/2016/16-576/TESTIMONY/16-576_2016-10-24_LEBANON_ATT_DTESTIMONY_C_BELOW.PDF.