

SOLAR NET METERING INCREASES UTILITY-SUPPLIER PROFIT MARGINS

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ABSTRACT

Net metering is an incentive that is essential to most solar photovoltaic systems. Recently the burden placed upon local utilities is an issue some regulators have been asked to address. This research uses actual 2013 and 2014 solar production data from nearly 200 sites, wholesale electricity day-ahead pricing data, and utility-wide demand data. This is all analyzed by the hour for two full years for a western Pennsylvania based utility and an eastern Pennsylvania based utility and their wholesale generators. Results show electricity is 15% more valuable when solar PV systems are generating power and feeding the grid during good weather conditions than at night or cloudy days when solar customers get energy back from the grid.

Solar energy generation is highly predictable in the day-ahead market, and leads to suppression in market prices for electricity. Thus to reveal the true impact of this market suppression, an increased solar renewable portfolio standard (RPS) fraction of 0.2 to 10% was simulated. This caused a decrease in demand resulting in a corresponding reduction in the price of electricity yielding savings to the utility. The maximum rate of increase and decrease in the utility-wide load did not change significantly until the solar RPS exceeded 5%. Additionally, the demand for electricity was reduced during the highest load hours of the year that corresponded to the most expensive hours of the year. The minimum base-load of the year was decreased substantially for solar RPS of 5% or greater and the base load reaches zero for solar RPS over 10%.

From the data of these two years, it is demonstrated that an increased use of solar energy would lead to savings that are larger than the loss in revenue due to having fewer traditional non-solar customers. Thus electricity suppliers and utilities stand to have both higher profits and higher profit margins when customers adopt net-metered solar energy compared to the non-adoption of solar energy.

INTRODUCTION

The Energy Policy Act of 2005 [1] requires electric utilities to offer Net Metering to customers who generate their own electricity. Of the various customer-sited technologies that can utilize net metering, solar photovoltaic is the fastest growing energy technology today with a 30% growth from 2014 to 2015 [2]. Net Metering is critical for a customer to fully realize the benefits of solar power because it allows a customer to generate excess electricity during the day (when the customer is not home and the solar irradiance is the greatest), and to use that energy at night (when the customer is home and the sun is not shining at all). The idea is that the customer's meter spins backwards during good solar hours, forward during bad solar hours, and the customer is billed only for the difference. Without net metering, it would be necessary to use some type of energy storage system which would dramatically increase the capital cost and maintenance of a customer-sited energy generation system.

In reality, net meters are not usually analog meters that 'spin' but rather digital meters that have two readings. One reading is for the electricity that would normally spin a meter forwards, and another reading for the electricity that would normally spin a meter backwards.

Pennsylvania has a deregulated electricity market in which most customers can choose their supplier of electricity. The supplier in turn purchases the generation of energy directly from power plants or independent generators. Customers do not have the ability to choose which utility provides the distribution of their electricity. Public utilities are governed by the Pennsylvania Public Utilities Commission, whereas rural electric cooperatives are governed by their membership and municipal electric authorities are governed by locally elected officials or political appointees. The net metering rules for public utilities are governed by the state Public Utilities Commission whereas the net metering rules for cooperatives and municipal authorities vary a great deal.

In 2013, Pennsylvania's electricity generation was 220 million MWh [3]. Of this only about 0.1% was satisfied by the

174 MW of installed solar energy [4]. Data for 2014 is essentially the same.

Some electric utilities claim [5] net metering places a burden upon the utility. The utility has to accept this ‘excess’ electricity during the day, and it also has to generate and provide the energy at night when the customer wants the energy ‘returned’. The utility must do all this without being paid. Indeed there is a wide variety in the way that net metering is administered by utility companies with some applying the basic concept above to both the generation and distribution portions of a customer’s bill, while others apply the net metering rule only to the generation portion of a customer’s bill. In the extreme case, at least one Pennsylvania municipal utility charges customers a distribution fee for both the energy the customer self-generates and the energy used from the utility [6]. This is in addition to requiring the customer to pay the full costs for any upgrades to the distribution system required to support the customer generation.

On the other hand, it is often said that it is beneficial to the national power grid to have distributed power generation such as a customer’s roof-top solar [7]. Such distributed power generation alleviates electrical transmission congestion and overload of the local distribution system. The Vermont Public Service Department reviewed many of the studies that assessed the costs and benefits of distributed solar [8].

In the California energy market, solar energy supplied about 5% of all in-state electricity generation [9]. However because this is solar energy, it is not consistently generated throughout the year. The California ISO has recently released what they coined the ‘Duck Curve’ (see Fig. 1) to illustrate some difficulties faced by the electric grid balancing authority in a robust solar market [10]. It should be noted that the particular day illustrated by Fig. 1 is not representative of the entire year and that perhaps it represents the worst-case scenario rather than the typical scenario because it is a mild spring weekend day.

It is normal policy for utilities and grid balancing authorities to estimate how much energy may be needed in a future year, day, or even hour and how much solar energy is likely to be produced in those future time periods. In the PJM grid region, the grid balancing authority knows detailed information about the pitch and orientation of every grid-tied solar PV system as well as the module and inverter specifications of these systems. Thus when combined with a weather forecast, it is possible to make an accurate prediction of the solar generation that will occur the following day. In fact, PJM makes its daily wind energy forecast [11] available publically each day and the forecast for December 22, 2015 is shown in Fig. 2.

The goal of this research is to determine the actual financial impact to the electric industry from the Net Metering of solar energy. Others have calculated the value of solar energy due to market suppression [12], but these methods used modeled data and not real data due to the difficulty of

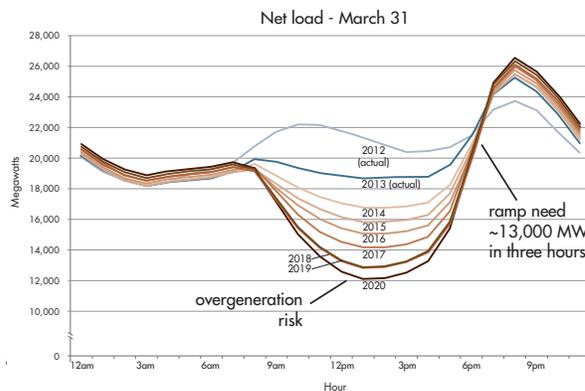


Figure 1: The Duck Chart as created by the California ISO showing the potential over generation of solar energy and the subsequent large ramp-up that occurs at sunset. Licensed with permission from the California ISO. Any statements, conclusions, summaries or other commentaries expressed herein do not reflect the opinions or endorsement of the California ISO.

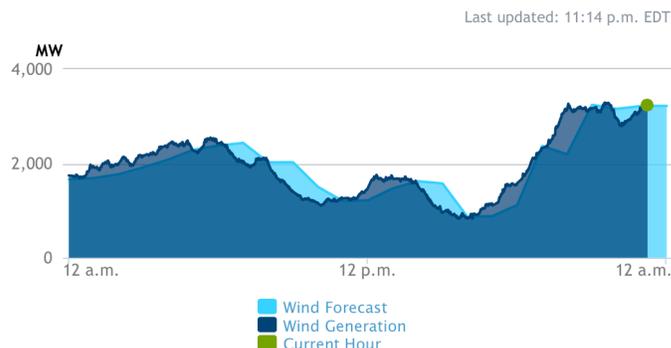


Figure 2: The predicted and actual wind energy forecast for the PJM region. The prediction is remarkably close to the actual production.

assembling a sufficient amount of real distributed solar data. Data is currently available for the historic hourly wholesale price of delivered electricity for every different electrical substation in Pennsylvania and the surrounding states. There are also thousands of customer owned solar PV arrays in the same region, many with data monitoring systems already installed and several years of solar production data. This study analyzes these data sets to compare the wholesale price of electricity and how much electricity actual solar PV systems are generating for each hour of the year. Also considered is the utility load at each hour of the year.

METHODS AND DATA Region And Time Studied

Two Pennsylvania public utilities were studied, Philadelphia Electric Company (PECO) which serves about one million customers in Philadelphia and surrounding areas, and Duquesne Light Company (DUQ) which serves 340,000 customers in Pittsburgh and surrounding areas. Data was collected for calendar years 2013 and 2014.

For each utility service area, historical hourly data for a large number of solar arrays was collected and aggregated by utility. This was then compared to the hourly load and wholesale Day-Ahead Location Marginal Price (LMP) of electricity as reported by the PJM Interconnection regional transmission organization.

Sources Of Publicly Available Data

Within the two service territories, solar production data was collected from all publicly available systems utilizing the Enphase® Enlighten® data collection system [13]. Enphase is 9th largest PV inverter manufacturer as reported by IHS for 2013 [14] and their data collection system had a larger number of systems in Pennsylvania than any other system the author could locate. Although solar arrays are generally facing south and tilted at 30 degrees, there is a wide variety of azimuth and inclination angles represented by these various systems. There is also a wide variety of shading characteristics represented by these systems. Only the data from solar arrays that have hourly data for all of 2013 and 2014 are included.

A very large number of solar arrays reported zero energy production on certain winter days likely due to snow fall. Additionally there was an average of <1% of solar arrays that report zero energy production on any given day regardless of weather. This may have been due to local power outages or maintenance, or could have simply been faulty data. It is assumed that such lapses are negligible when aggregated with the other 99% of solar production data. However, there was also an issue that some solar arrays appeared to have data monitoring issues in which the daily production of electricity for a day, or sometimes for many months, was simply averaged over all day-time hours for that period. Sites that had this latter issue were removed from the analyzed data set. In the DUQ territory, there were a total of 32 sites kept in the data pool. In the PECO territory there were a total of 141 sites kept in the data pool.

The PJM Data utilized were the hourly Locational Marginal Price (LMP) for day-ahead purchase (total of generation, congestion and marginal loss) as obtained from the PJM Data Miner [15] for all pnodes within each utility service area. PJM also makes available utility wide hourly load data as reported by the various utilities [16].

Aggregation Of Data

Solar production data is reported by Enphase® Enlighten® graphically in 15 minute intervals and time-stamped for the date and time at the end of each interval. This graphical data was converted to numerical data, and these intervals were summed to yield hourly production data. The precision of this graphical to numerical conversion is 1% of the maximum possible 15 minute production for that site. For each given hour in the two year period, the solar production for all available solar arrays within each utility service area were combined to give a total solar production amount.

For each hour of 2013 and 2014, the total day-ahead LMP for all the various pnodes (local delivery point of wholesale

electricity) was then averaged for each utility. Because no publically available data could be found for the load at each pnode, a weighted average was not possible.

Because no data is available for the hourly load of all the various distributed solar PV arrays and their users, it is assumed that the total of all solar customers had a daily load profile equivalent to the utility-wide average load profile. It was also assumed that the annual total solar energy production of these solar customers was equal to the annual electric demand of these customers. These two assumptions and their impact is discussed in the General Discussion.

All data was aggregated and analyzed using Excel® VBA.

Value Of Deposited And Withdrawn Solar Energy

The solar production data, wholesale price, and utility load data were analyzed by the hour to compare the value of *deposited* solar energy to the value of *withdrawn* solar energy as illustrated in Fig. 3. The *directly used* energy had no value calculated in this part of the analysis because it doesn't directly involve the utility infrastructure.

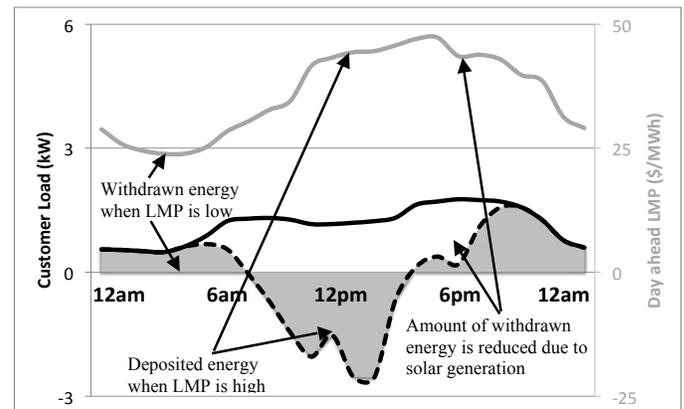


Figure 3: Illustration of deposited and withdrawn energy during a hypothetical day for a single solar customer. Grey line shows the day ahead LMP at the same times using the right axis.

Because no data is available for the hourly load of all the various distributed solar PV arrays and their users, a fictitious solar customer was created based on the aggregate data of all solar generation within the utility district. This fictitious customer had exactly 10,000 kWh of solar generated electricity annually and an annual demand of exactly 10,000 kWh which is equivalent to a small residential customer. The hourly solar generation was set to the aggregate hourly generation of all systems collected for the region and normalized to 10,000 kWh per year. The hourly load for this fictitious customer was set to the hourly load of the entire utility region normalized to 10,000 kWh per year.

Table 1 shows the actual data of July 18, 2013 for this analysis of a fictitious solar customer in the DUQ district. This day was selected because it was the highest load day for 2013. This was not a typical day, but none-the-less this table illustrates the method used to analyze all hours of the year.

Table 1: Hour-by-hour data shown for July 18, 2013 for the Duquesne Light Company territory. This was the day in 2013 that had the highest reported load for the DUQ territory. Also shown are the hour-by-hour normalized data for a single fictitious solar customer and what the utility wide load would be with a 5% solar fraction.

Date	Hour	Existing solar generation, utility-wide load, and LMP price				Single fictitious 10,000 kWh/yr solar customer				Utility-wide load with 5% solar fraction		
		Solar Wh Monitored	Utility-Wide Load (MWh)	Total LMP (day-ahead) \$/MWh	Load Bin	Solar generation normalized to 10,000 kWh/yr (kWh)	Customer load normalized to 10,000 kWh/yr (kWh)	Net Metered (kWh)	Deposited and withdrawn kWh value	5% Solar fraction generation (MWh)	New utility load with additional solar generation (MWh)	New Load Bin
7/18/13	1	0	2022	41.22	20	0.000	1.364	1.364	\$0.056	0	2022	20
7/18/13	2	0	1939	33.01	19	0.000	1.308	1.308	\$0.043	0	1939	19
7/18/13	3	0	1874	29.89	18	0.000	1.264	1.264	\$0.038	0	1874	18
7/18/13	4	0	1833	28.32	18	0.000	1.236	1.236	\$0.035	0	1833	18
7/18/13	5	1535	1819	27.71	18	0.122	1.227	1.105	\$0.031	9	1810	18
7/18/13	6	3518	1872	29.76	18	0.279	1.263	0.983	\$0.029	21	1851	18
7/18/13	7	9414	1954	33.77	19	0.747	1.318	0.571	\$0.019	55	1899	18
7/18/13	8	22850	2079	41.56	20	1.814	1.402	-0.412	(\$0.017)	134	1945	19
7/18/13	9	39814	2250	47.63	22	3.161	1.518	-1.644	(\$0.078)	234	2016	20
7/18/13	10	53892	2431	56.54	24	4.279	1.640	-2.639	(\$0.149)	317	2114	21
7/18/13	11	54820	2600	78.88	26	4.353	1.754	-2.599	(\$0.205)	323	2277	22
7/18/13	12	61035	2751	103.44	27	4.846	1.856	-2.991	(\$0.309)	359	2392	23
7/18/13	13	62525	2836	141.15	28	4.964	1.913	-3.052	(\$0.431)	368	2468	24
7/18/13	14	64480	2899	182.00	28	5.120	1.955	-3.164	(\$0.576)	380	2519	25
7/18/13	15	60493	2940	227.88	29	4.803	1.983	-2.820	(\$0.643)	356	2584	25
7/18/13	16	53431	2951	286.50	29	4.242	1.990	-2.252	(\$0.645)	314	2637	26
7/18/13	17	39270	2931	303.38	29	3.118	1.977	-1.141	(\$0.346)	231	2700	27
7/18/13	18	21331	2915	262.26	29	1.694	1.966	0.273	\$0.071	126	2789	27
7/18/13	19	11995	2891	179.63	28	0.952	1.950	0.998	\$0.179	71	2820	28
7/18/13	20	4610	2851	100.05	28	0.366	1.923	1.557	\$0.156	27	2824	28
7/18/13	21	1779	2797	94.62	27	0.141	1.887	1.745	\$0.165	10	2787	27
7/18/13	22	0	2739	76.72	27	0.000	1.847	1.847	\$0.142	0	2739	27
7/18/13	23	0	2605	55.81	26	0.000	1.757	1.757	\$0.098	0	2605	26
7/18/13	24	0	2388	46.63	23	0.000	1.611	1.611	\$0.075	0	2388	23

The yearly totals for 2013 and 2014 for both utility districts are given in Table 2. Table 3 repeats the analysis of Table 2, but only includes data from March-December of each year so that the effects of the extreme winter of 2014 can be removed.

Table 2: Annual price difference between deposited and withdrawn (net metered) electricity for a fictitious solar customer using 10,000 kWh/year and generating 10,000 kWh/year of solar energy within each of the two utility territories.

	Duquesne Light Company (DUQ)		Philadelphia Electric Company (PECO)	
	2013	2014	2013	2014
Deposited kWh	6016	6030	5885	5867
Average \$/kWh deposited	0.039	0.042	0.043	0.047
Withdrawn kWh	6016	6030	5885	5867
Average \$/kWh withdrawn	0.034	0.044	0.037	0.061
Annual difference in percent	16%	-4%	15%	-23%

Table 3: March-December price difference between deposited and withdrawn (net metered) electricity for a fictitious solar customer using 10,000 kWh/year and generating 10,000 kWh/year of solar energy within each of the two utility territories.

	Duquesne Light Company (DUQ)		Philadelphia Electric Company (PECO)	
	2013	2014	2013	2014
Deposited kWh	5729	5767	5331	5461
Average \$/kWh deposited	0.039	0.041	0.043	0.043
Withdrawn kWh	4778	4675	4700	4527
Average \$/kWh withdrawn	0.034	0.035	0.037	0.038
Annual difference in percent	15%	16%	17%	12%

Cost Vs. Load

The wholesale day-ahead cost of electricity (total LMP) was plotted for each utility region for 2013 and 2014. This data shows a clear relationship of increasing price that becomes exponential at very high loads. The relationship is complicated to model because there are other factors such as the length of time spent at a high load that affects the price of electricity. The relationship is also relatively linear for low loads, but at high loads, the relationship becomes very non-linear.

Figure 4 shows the day-ahead LMP vs. the utility wide load. Graphs for each utility are remarkably similar despite being located 250 miles apart. 2013 and 2014 are similar except for the unusual peak in price for moderate loads that occurs in 2014 for both utilities. The cause of this anomaly in 2014 was due to the extreme cold that was experienced in both January and February.

The extreme cold weather in the northeast United States of early 2014 had a very clear impact on the price of electricity as the price spiked very high even though the load was only moderate. This represents a high demand for natural gas for space heating which competed with electricity generation.

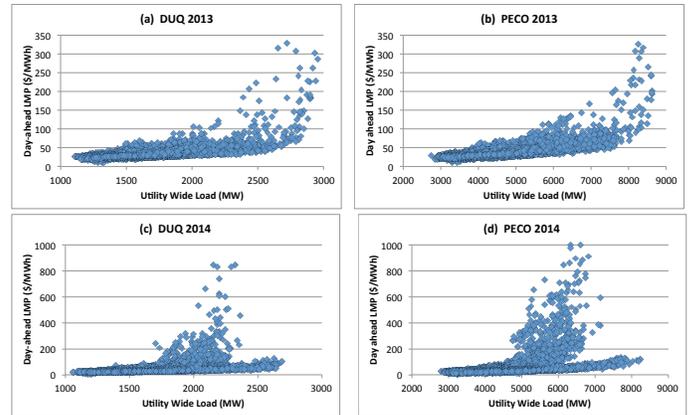


Figure 4: Day-ahead LMP vs. utility-wide load for (a) DUQ in 2013, (b) PECO in 2013 (c) DUQ in 2014, and (d) PECO in 2014.

Bin Analysis Of Cost And Load Data

The day-ahead LMP was not modeled with a best-fit curve but rather divided into bins of 100 MW in size. Within each bin (e.g. 2000 MW – 2099 MW), the number of occurrences, mean price, and standard error of the mean was obtained for that range of loads or ‘bin’.

Standard deviations, and thus standard error of the mean, require at least two data to be calculated. For any bin which contained fewer than 2 occurrences, the standard error in the mean was automatically set to 5% of the mean price. For small loads, where this can be relevant to the data analysis, this 5% is an overestimate of the error. As can be seen in Table 4, the standard error of the mean tends to be about 1% at low loads.

It is assumed that for any adjusted loads that are smaller than the original lowest load of the year, the mean price, standard deviation, and standard error of the mean would be the same as for the lowest hourly load that did occur in that year.

Table 4 shows the same data of Fig. 4a but with the addition of the bin data that is described below.

Scale Up Of Solar Fraction

To determine the impact that a greater use of solar energy would have on the cost vs. load relationship, the annual amount of customer-generated solar energy was scaled to 0.2%, 0.5%, 1%, 2%, 5% and 10% of the annual energy demand within the utility’s service district. Then, using the same utility-wide load and the new scaled-up generation of solar energy, the amount of energy needed from the various suppliers was calculated for each hour. At many times, the increased amount of solar energy created a substantial drop in the utility-wide load.

Figure 5 shows this effect for July 18, 2013 with a 5% solar fraction in the DUQ utility district. Figure 5 is not meant to be representative of all days because it is the highest load day of the year. Other days show substantially different load profiles depending on demand and weather. For instance Fig. 6 shows differing effects during mild weather on two clear days with very high solar production. Figure 6a is a Friday (5/3/2013) and Fig. 6b is a Sunday (5/5/2013).

Table 4: Number of occurrences and Mean day-ahead LMP by load range both before and after a 5% solar fraction for the DUQ service territory in 2013. Also shown is the total price paid for all electricity within each load range both before and after the 5% solar fraction. The uncertainty in total price is based on the standard error of the mean day-ahead LMP.

Bin	Load	Without Increased Solar Generation						With 5% Solar RPS			
		Mean Day-Ahead LMP	Standard error of the mean	Number of hours per year	Total MWh Supplied	Current Total Price	Uncertainty in total price	Number of hours per year	Total MWh Supplied	Solar RPS Total Price	Uncertainty in total price
0	0 - 99	24.3	0.3	0				0			
1	100 - 199	24.3	0.3	0				0			
2	200 - 299	24.3	0.3	0				0			
3	300 - 399	24.3	0.3	0				0			
4	400 - 499	24.3	0.3	0				0			
5	500 - 599	24.3	0.3	0				0			
6	600 - 699	24.3	0.3	0				0			
7	700 - 799	24.3	0.3	0				2	1,500	36,450	450
8	800 - 899	24.3	0.3	0				20	17,000	413,100	5,100
9	900 - 999	24.3	0.3	0				42	39,900	969,570	11,970
10	1000 - 1099	24.3	0.3	0				70	73,500	1,786,050	22,050
11	1100 - 1199	24.3	0.3	79	90,850	2,207,655	27,255	244	280,600	6,818,580	84,180
12	1200 - 1299	25.0	0.2	452	565,000	14,125,000	113,000	677	846,250	21,156,250	169,250
13	1300 - 1399	26.3	0.1	744	1,004,400	26,415,720	100,440	978	1,320,300	34,723,890	132,030
14	1400 - 1499	28.8	0.2	978	1,418,100	40,841,280	283,620	1166	1,690,700	48,692,160	338,140
15	1500 - 1599	30.8	0.2	1152	1,785,600	54,996,480	357,120	1313	2,035,150	62,682,620	407,030
16	1600 - 1699	33.8	0.2	1339	2,209,350	74,676,030	441,870	1262	2,082,300	70,381,740	416,460
17	1700 - 1799	34.8	0.2	1324	2,317,000	80,631,600	463,400	1058	1,851,500	64,432,200	370,300
18	1800 - 1899	36.6	0.2	1026	1,898,100	69,470,460	379,620	780	1,443,000	52,813,800	288,600
19	1900 - 1999	38.7	0.3	628	1,224,600	47,392,020	367,380	478	932,100	36,072,270	279,630
20	2000 - 2099	42.0	0.5	369	756,450	31,770,900	378,225	259	530,950	22,299,900	265,475
21	2100 - 2199	44.0	0.9	189	406,350	17,879,400	365,715	139	298,850	13,149,400	268,965
22	2200 - 2299	46.1	0.7	169	380,250	17,529,525	266,175	98	220,500	10,165,050	154,350
23	2300 - 2399	52.2	1.8	119	279,650	14,597,730	503,370	87	204,450	10,672,290	368,010
24	2400 - 2499	62.6	3.5	82	200,900	12,576,340	703,150	34	83,300	5,214,580	291,550
25	2500 - 2599	68.3	5.1	37	94,350	6,444,105	481,185	21	53,550	3,657,465	273,105
26	2600 - 2699	90.2	13.6	23	60,950	5,497,690	828,920	17	45,050	4,063,510	612,680
27	2700 - 2799	112.4	16.3	21	57,750	6,491,100	941,325	12	33,000	3,709,200	537,900
28	2800 - 2899	159.6	10.1	25	71,250	11,371,500	719,625	3	8,550	1,364,580	86,355
29	2900 - 2999	270.0	16.4	4	11,800	3,186,000	193,520	0			
30	3000 - 3099	.0	0.0	0				0			
31	3100 - 3199	.0	0.0	0				0			
Total:					14,832,700	538,100,535	2,091,924		14,092,000	475,274,655	1,392,734
Average Cost/MWh							\$36.28 ± 0.14				\$33.73 ± 0.10
								Percent savings			7.0 ± 0.5 %

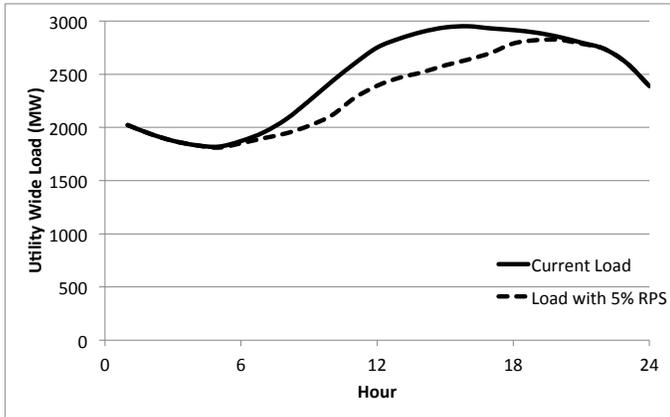


Figure 5: July 18, 2013 before and after 5% solar RPS for the DUQ territory.

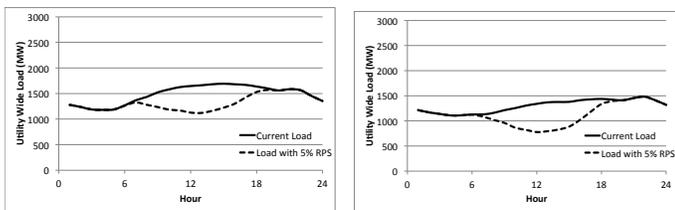


Figure 6: (a) Friday, May 3, 2013 (left) and (b) Sunday, May 5, 2013 (right) before and after a 5% solar RPS in the DUQ territory.

To determine the total cost to obtain all electricity, it was assumed that all power was purchased in the day-ahead market. This assumption is not true because a considerable amount of energy is purchased with long-term contracts many months or even years in advance. This assumption is unavoidable and will be discussed further in the General Discussion. However even if only half of electricity is purchased in the day-ahead market, then a proportionate amount of savings are still achieved.

The total cost without and the total cost with the simulated solar RPS is determined by adding the cost to obtain all the energy for each load bin as shown in Table 4. The total cost for each bin is the number of times a load in the bin occurred multiplied by the load and mean LMP price of that bin. This is done both without the simulated solar RPS and with the simulated RPS. Table 4 shows that the simulated solar RPS shifts many occurrences of a given load bin to lower load bins.

Because there is an error in the mean LMP price for each bin (i.e. the standard error in the mean), the total cost for each bin (both with and without the solar RPS) has an error associated with it. This error provides assurance that any savings realized are significant when compared to the variation of LMP prices that occur for a given load as seen in Fig. 4.

The total price to obtain all electricity both without and with the solar RPS is then simply the sum of the cost for each bin. The error in this total price is determined by propagation of errors.

Finally, Table 4 also shows the average cost per MWh of electricity sold to customers both before and after the simulated

solar RPS. Note that after the solar RPS, there are fewer MWh sold to customers (5% fewer for the 5% solar RPS case), thus the average cost per MWh takes into account that there is less energy that will be bought and sold by suppliers as well as the fact that the solar RPS has suppressed the market price of the energy that is transacted. The savings are given showing that the solar RPS does indeed lower the overall cost to obtain all electricity for the utility's customers. Again the errors stated for the average costs and the percent savings are found using propagation of errors.

Not shown in detail is the same algorithm applied to both service territories for both years with solar fractions of 0.2% to 10%. Summary data is shown in Fig. 7 for the percent savings depending on year, utility, and solar RPS.

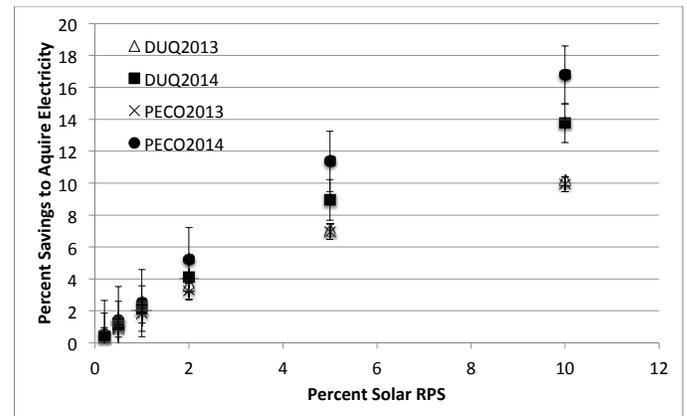


Figure 7: Percent savings that electricity suppliers would have with various levels of solar RPS for both 2013 and 2014 and in the both the DUQ territory and the PECO territory.

Impact On Load Ramp-Up, Ramp-Down, And The Potential Over-Generation Of Solar Energy

To address the concerns of the so-called “Duck-Graph” of Fig. 1, the greatest 3-hr ramp-up, greatest 3-hr ramp-down, the lowest load demand, and the maximum load demand were calculated both at current conditions (~0.1% solar RPS) and with increased solar RPS. This data is shown in Fig. 8a and 8b for the greatest ramp-ups and ramp-downs. Figure 9 shows the maximum and minimum loads for the DUQ territory and the PECO territory.

RESULTS AND DISCUSSION

General Discussion

Very little energy is purchased in the real-time market. Thus the impact on real-time prices was not analyzed. Ideally, long-term contracts should be analyzed because a substantial portion of energy is purchased by long-term contract. However the details of these contracts are proprietary and are unavailable for analysis.

It would be a simple matter to analyze the load at each node and to give a weighted average for the day-ahead LMP

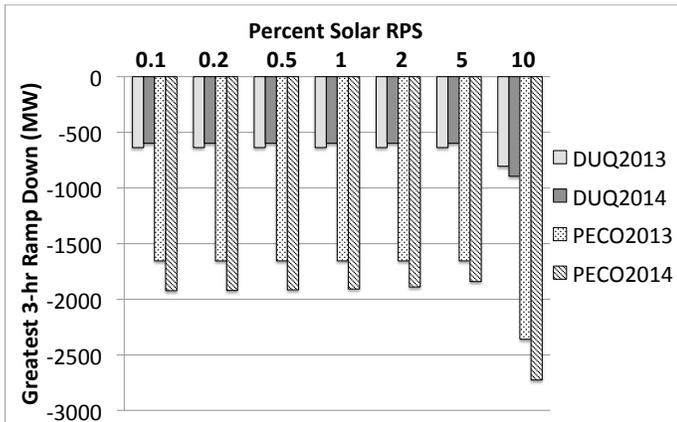
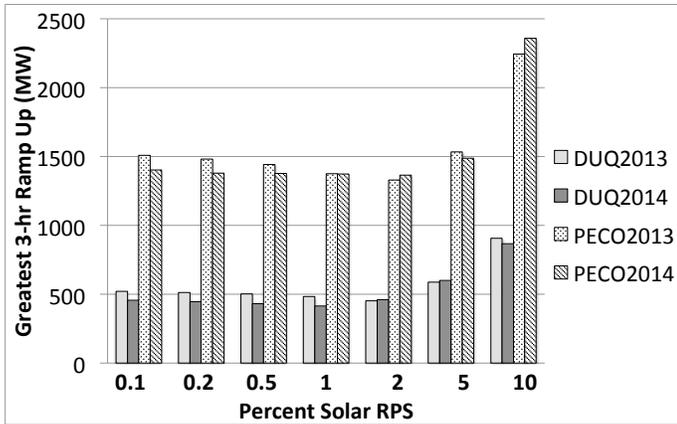


Figure 8: The greatest (a) 3-hr ramp-up and (b) 3-hr ramp-down in utility-wide load for various levels of solar RPS.

for each hour. But the data was not available for this. However the prices for several different pnodes were analyzed separately (rural, suburban, urban) and there was no clear difference between the results. Thus it is likely that a weighted average will yield similar results.

It is definitely desirable to know the load profile of a typical solar consumer if such a thing exists. It is certainly the case that the typical residential consumer has a different load profile than the overall utility load profile. Knowing this information would lead to a more accurate measurement of the difference between the value of deposited and withdrawn electricity. This difference for a particular customer could change in either direction and it could negate or enhance any impact caused by extreme cold weather. However as long as all types of customers use solar energy, this effect should average out from the utility's perspective.

Knowing the individual load profile of various solar customers would not impact the larger results pertaining to market suppression from a larger solar RPS. The savings from a larger solar RPS all deal with regional scale issues, so there would be no change in any of the discussion about the impact on the maximum load, minimum load, ramp-up or ramp-down of loads.

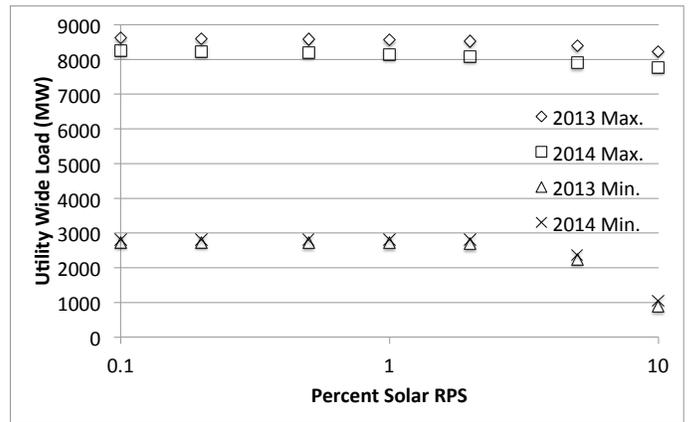
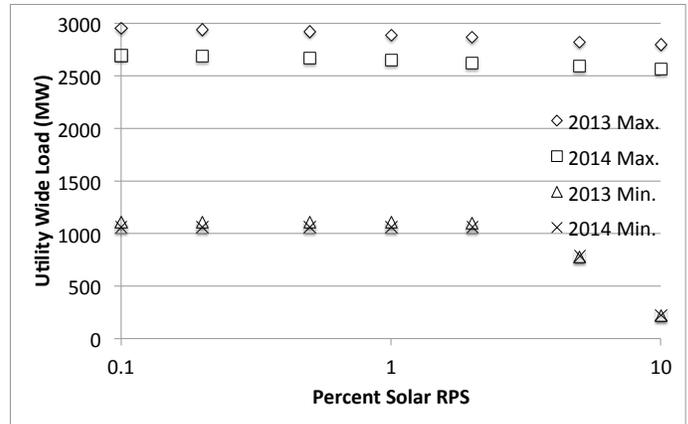


Figure 9: The maximum and minimum loads for the (a) DUQ territory and the (b) PECO territory for various levels of solar RPS.

Price Difference Between Deposited And Withdrawn Electricity And The Effect Of Extreme Cold Weather

In 2013, deposited energy was more valuable than withdrawn energy by 16% in DUQ and by 15% in PECO (see Table 2). But in 2014, the price differential was in the other direction with withdrawn energy being more valuable by 4% in DUQ and by 23% in PECO.

This is an interesting result for 2014 and can be explained by a more careful analysis of the data shown in Fig. 4b and 4d. These figures indicate many hours of very high day-ahead LMP when the load is not particularly high. Upon inspection, the very high day-ahead LMPs occurred not during hot summer afternoons but during January and February, both during nighttime and day-time hours. When these days were compared to weather data, these days correspond to the extreme cold weather events of 2014 in which record lows were set across the northeast including Pittsburgh and Philadelphia.

In the DUQ district (Pittsburgh), there were 20 days in January and February 2014 in which the total day-ahead LMP was over \$100/MWh at some hour during the day. On each but one of these 20 days, record low temperatures were either set or tied. Ten days within Pittsburgh, nine days in areas around Pittsburgh. In 2013, the total LMP was never over \$100/MWh during winter months for the DUQ district. Not only was the

day-ahead LMP high on these 20 cold-weather days, it peaked at nearly three times higher than the most expensive (summer) day-ahead LMP of 2013.

In the PECO district, there were no days in January and February 2013 with day-ahead LMPs over \$135/MWh. Whereas in 2014, there were 22 days with prices over this amount, and one day with a price over \$1000/MWh.

In the state of Pennsylvania in general, there were 280 daily record low temperatures set or tied in January and February 2014. The average number of record low temperatures set or tied in Pennsylvania for January and February of the previous 25 years was 34 per year. Perhaps marking a more clear distinction between 2013 and 2014 is that there were only 2 record low temperatures set in January and February of 2013. So not only was 2014 a very cold winter, but 2013 by comparison was a warm winter [17].

When January and February data are removed for both 2013 and 2014, the price difference between the deposited energy and the withdrawn energy is remarkably similar for 2013 and 2014. The deposited energy in 2013 was 15% more than the withdrawn energy and 16% more in 2014 as shown in Table 3 for DUQ. For PECO, the deposited energy was 17% more than the withdrawn energy in 2013, and in 2014 it was 12% more.

This analysis was based on a fictitious solar customer who has a photovoltaic system that produces exactly the same amount of energy that the customer uses on an annual basis which is quite unusual for Pennsylvania. This is unlikely for a residential consumer because most two-story homes (such as those most common in Pennsylvania) do not have south-facing roof space to host a PV system large enough to meet the home's annual consumption. This is aggravated by the fact that most solar systems in Pennsylvania were constructed under the PA-Sunshine incentive program which capped residential systems at 10 kW.

So it is more likely that the typical solar customer may have a net-zero metered system from April to sometime in late fall or early winter. Then this typical customer is billed for electric consumption during the winter months of January, February, and March (when cold). In this case Table 3, which considers only March-December, would be the correct time frame to use although the numerical analysis would change slightly. There is still another issue in the finer details of this analysis. No fictitious user would actually have a daily load profile that matches that of the utility wide load profile. Thus, depending on the actual load profile of any individual solar customer, the electric industry may benefit a great deal more or less than the average 15% given in table 3. But assuming that all customer classes are equally likely to adopt solar energy, then 15% should be a good approximation for the average benefit that the electric industry receives from all customers who use net-metered solar energy.

This is an important result, because it shows that the electric industry BENEFITS financially from the net-metering of solar energy provided that winter temperatures are not too low or that most customers do not meet 100% of their annual

consumption with solar energy. The typical solar customer deposits excess solar generation when wholesale rates tend to be high. This reduces the need for suppliers to purchase this power at these higher rates. Then the solar customer withdraws this energy when the rates tend to be 15% lower. Energy suppliers then have to purchase this energy to be returned to the solar customers per the terms of net metering, but because this energy is priced 15% less than when the supplier would otherwise have had to purchase energy, the supplier reduces their expenses and increases their profit and profit margins.

This 15% price differential multiplied by the 10,000 kWh/yr and an average wholesale generation charge of 4 cents/kWh, equates to \$60/year for each 9000 W solar PV system (which would likely generate 10,000 kWh/yr). This may not appear to be much, but it is certainly the opposite from what is being proposed by utilities who are pursuing monthly surcharges for solar customers [18].

The unusual results in extremely cold weather are likely due to competition for natural gas resources [19] between power plants and direct space heating. This competition is enhanced because the Pennsylvania mix of power plants is evolving from mainly coal powered to mainly natural gas powered. Fortunately, this competition seems to be limited to only periods of extended extremely cold weather, more than just one cold day. Also, in the long term, this effect may vanish with greater natural gas storage and pipeline capacity.

It is worth commenting that while not a subject of this paper, February 2015 was the coldest winter on record for Pennsylvania with a whopping 323 record low temperatures set. As a result the electricity prices for 2015 also spiked very high just like in 2014. The switch from coal to natural gas is going to continue and only increase the competition for natural gas in the future. Thus if extremely cold weather becomes a regular occurrence in the northeast, this winter-time peak in LMP may become normal. Or conversely, climate change may make extreme winters less likely and instead increase the likelihood of warm winters making the results of 2013 more common.

Simulated Increased Solar Fraction

Day-ahead LMP prices are bid upon after the balancing authority has made its prediction for the next day's electricity demand. Furthermore the balancing authority (PJM) also uses the predicted weather and details about the existing solar generation capability to make this prediction. Because of these predictions, settlement prices for the day-ahead LMP market have already been adjusted to account for the solar generation that will occur. This inherent adjustment masks the true value of solar energy. That is, on a hot summer day when the price would otherwise be very high, the price is inherently lower because all involved parties know that solar energy will be there reducing the demand for energy regardless of the bids made by the various power producers.

One way to determine by how much solar energy depresses wholesale day-ahead LMP prices is to scale up the amount of solar energy generated and to keep the LMP cost at a given load the same as if there was no increased solar. Figure 5

shows how an increased amount of solar energy (5% of all energy consumed which is about 50x more solar than is presently generated in Pennsylvania) changes the utility-wide load profile on July 18, 2013 such that less electricity must be generated to meet demand. Table 4 shows the average 2013 day-ahead LMP prices for loads that fall into each load bin. Assuming these prices remain fixed for a given load, then because less energy will be required to be generated, wholesale prices will fall accordingly. The effect of this reduced amount of required electric generation are shown in Table 4 for the entire year. Figure 7 gives the expected percent savings for the various suppliers and utilities to purchase electricity for their customers in both years and both territories, and for various solar RPS from 0.2% (twice 2013 amount of distributed solar) to 10% (100x as much distributed solar as 2013).

Pennsylvania has a mandated renewable energy portfolio standard (RPS) which includes a specific carve out for solar energy. The solar RPS is required to reach 0.5% by 2020. This was an amount that was simulated in the study. From Fig. 7 it can be seen that a 0.5% solar RPS results in a 1% savings to the utilities and energy suppliers. But at this low level of savings the uncertainty in the savings is large, thus most of the discussion in this study is based upon a 5% solar RPS. A 5% solar RPS results in a level of savings which is more clearly defined even when the uncertainty is considered.

Furthermore, the solar RPS in Pennsylvania is managed using the solar renewable energy credit (SREC) market. Pennsylvania is one of the few states that allows SRECs to be counted toward the solar RPS even when the solar energy is generated out of state. As of the writing of this paper, there was more solar energy installed in North Carolina meeting the Pennsylvania RPS than that installed in Pennsylvania.

This study assumes that solar energy is generated not only in the same state, but within the same utility district. Thus the savings that are indicated by this research are not necessarily achieved under the market conditions required by the current PA RPS/SREC program.

Solar Energy Increases Profits And Profit Margins For Energy Suppliers

The results of Fig. 7 clearly indicate that for all increased levels of solar generation considered, there is a substantial financial savings to be realized by the electric industry due to the lowering of wholesale day-ahead LMP prices. Solar energy lowers demand for electricity when prices tend to be high and thus by lowering this demand at a time when prices are very sensitive to demand a substantial impact on the wholesale price for all energy is to be made. It is possible that by having only 5% of all customers using solar energy, the price of electricity for the remaining 95% of customers can be reduced by 8-10%.

Interestingly, with a 5% solar RPS, the suppliers of electricity will lose 5% of their customer base and thus also 5% of their gross revenues. But at the same time, they will save 8-10% of their expenses to purchase electricity. Thus the actual profits of these suppliers will increase at the same time that

they are losing customer base. Their profit margins, which are based on gross revenues, will increase an even larger amount, about 15%. This represents something close to a doubling or even tripling of the profit margin of many energy suppliers assuming their profit margins are already in the 5% range. Some of this will get passed along to consumers resulting in lower energy prices for all.

This means that solar energy not only benefits the customer who paid for the solar energy and thus has reduced their amount of purchased energy, solar energy also benefits non-solar customers because it lowers their price to purchase generated electricity. This result also supports the social value of solar energy incentives. The financial incentive may go to only the customers choosing to 'go solar', but the resulting financial savings will be experienced by all of society.

Solar Energy Reduces The Annual Maximum Demand For Electricity From Traditional Generators

In addition to lowering the generation costs of electricity, solar energy has other beneficial impacts on the electric industry. Solar energy reduces the annual maximum load on the electric grid (see Fig. 9) which means that fewer old and inefficient power plants will be called into service on days of high demand. Solar energy also lowers the frequency of high demand hours which means that the maintenance of these older and infrequently used units is less stressed.

These are also the units that tend to be the most polluting because pollution control measures are often not economical for units that are rarely called into service. Thus solar energy will have a disproportionately high reduction in the emissions from fossil fuel generators.

Solar Energy And The "Duck Chart"

There are two main concerns that are discussed in relation to the Duck Chart of Fig. 1. The first is that the 3-hr ramp-up and ramp-down of generation will be increased. For the regions investigated in this research, the amount of solar generation can be increased 50 fold without seeing any significant affect on the magnitude of ramp-up or ramp-down (see Fig. 8). With a 10% solar RPS (a 100x increase in solar), the magnitude of the largest 3-hr ramp-up is increased by about 25%. With a 10% solar RPS, the largest 3-hr ramp-down is approximately doubled.

The more significant impact is that the minimum load on the grid decreases substantially. Assuming that the daily load profile does not change, the minimum load is reduced to zero when solar accounts for 12% of all electricity generation on an annual basis. This would then imply that there would be no base-load generators (nuclear or coal) with solar fractions over 10%. However this does not happen on a regular basis. This would only happen on a mild-temperature, very sunny WEEKEND (see Fig. 6). This is certainly not a typical occurrence, and in fact it is even predictable days in advance.

Additionally a 10% solar RPS in Pennsylvania is a long way off. By the end of 2013 there was 180 MW of installed solar in Pennsylvania and this increased to 190 MW by the end

of 2014 which accounted for about 0.1% of all electricity generation. Thus at this rate of growth, it would take 2000 years to reach a solar fraction of 10%. Even if the growth rate of solar energy in Pennsylvania were to increase by 50% each year (a seemingly impossible scenario to sustain), it would still take over 15 years to reach this point.

Even if the rate of growth of solar energy in Pennsylvania were to increase by 50% each year for a decade, then solar energy would still only account for 1% of all energy generated. At this level, solar energy would still not decrease the minimum base-load generation. The effects on the minimum base-load begin to appear with solar fractions greater than 2%, and of course that is only on mild temperature, sunny, weekends.

At these higher solar fractions (2% and higher), the days and hours of minimum demand change as do the days and hours of the traditional maximum peak demand. This illustrates the need for long-term planning to change the traditional peak/off-peak rate structure, use of timed appliances, and other peak-shaving policies to adapt to the changing load patterns that will occur with a high solar RPS.

CONCLUSION

Despite the many publically reported concerns about solar energy creating a burden on the electric industry, this research shows that solar energy provides a substantial and tangible benefit to the electric industry and to society. Solar energy increases the profit margins of independent suppliers and utilities. In most cases, it is expected that competition will shift these financial savings along to the customers in the form of either rate decreases or the reduction of otherwise higher rate increases. Solar energy will also help electric generators to meet the new pollution standards proposed by the Clean Power Plan of 2015 while at the same time maintaining or even reducing the costs to consumers.

Not all parts of the electric industry are equally affected. In Pennsylvania, the industry can be divided into at least the following categories: public utilities, municipal utilities, cooperative utilities, independent suppliers, and independent generators.

Of these, the municipal utilities, cooperative utilities, and independent suppliers are the ones that stand to gain the most from the financial impact presented in this research. These three types of entities are the ones that purchase power on the wholesale market at variable rates and then resell to customers at mostly fixed rates. Some of these entities could even boost the savings that are discussed here by changing their incentives, or lack there of, for solar energy in an effort to increase the growth rate of solar energy within their particular territories.

Public Utilities will have somewhat less financial gain. Ideally, most public utility customers in Pennsylvania have selected an independent supplier for their electricity and thus there is no financial gain for the public utility in relation to the data presented here. However, there are still a considerable number of customers who chose to receive generation via the public utility's default service plan. The financial savings

discussed here do apply to public utilities servicing these customers.

On the other hand, as with anything in life, there are winners and losers. Independent generators are clearly the losers with solar energy. They will lose market share as well as the ability to charge higher rates during times of high demand. Many older and less efficient plants will be retired. Eventually, with much higher solar fractions, some modern and efficient generation facilities will be called into service less frequently. Thus this lost market share will adversely impact independent generators. However, this is the nature of competition ... Independent generators using fossil fuels will slowly be replaced by either distributed customer-owned solar energy or by independent generators using utility-scale solar energy.

From a consumer perspective, the most interesting aspect of this research is that solar energy benefits everyone. It certainly benefits the customer who chooses to own the solar directly, but it also benefits other customers who do not adopt solar energy because it makes their electricity less expensive to purchase on the wholesale market.

While the results of this research are known to apply only to the two utility areas, DUQ and PECO, in Pennsylvania, it most likely applies to all of Pennsylvania. These methods should now be applied to other regions of the nation, especially to regions where industry has been successful in creating new policies that adversely impact solar energy to see if these new policies are based on fact or hyperbole.

This research also indicates that in order to have a solar RPS of 10% or greater, substantial investment should be made for large scale energy storage. With energy storage, further reductions in the peak load can be made while keeping the minimum load high enough to support base power infrastructure. The cost of this energy storage could even come from the savings that are obtained from higher solar RPS as described in this work.

This research is limited to only analyzing the generation of electricity. Similar methods should be applied to the distribution of energy to see what financial impact solar may make on the distribution of energy.

DEFINITIONS

Deposited energy/electricity: This is the solar generated electricity that is in excess of what a solar customer needs on-site at the moment of generation. This electricity will back feed the meter and the grid, turning analog meters backwards, and generating a credit to be used at some time in the future by the solar customer.

Withdrawn energy/electricity: This is the non-solar electricity that a solar customer needs at night-time, or whenever the customer's actual use of energy exceeds the amount being generated at that moment. This electricity will run the meter forward as usual. If the solar customer does not have enough banked kWh, then this energy is paid for just like a normal bill would be paid.

Directly used energy/electricity: This is the solar generated electricity that is used by the customer at the same

moment it was generated. This electricity does not pass through the meter in either direction and is completely independent of the electrical grid.

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DISCLOSURE

Richard Flarend is a solar energy market participant by way of his solar installation business. This financial interest has been reviewed by The Pennsylvania State University's Individual Conflict of Interest Committee and is currently being managed by the University.