On the Business Case for Merchant Solar

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***Abstract*—This paper addresses what we call the *investment question*: Under what plausible circumstances, if any, can variable renewable energy (VRE, and solar photovoltaic (PV) in particular) be a good investment? Although VRE has been growing rapidly world-wide, it is generally subsidized. Under what cost and market conditions can solar PV flourish without subsidy? We employ solar insolation and market price data from the U.S. and from Germany to gain insight into the investment question. We find that unsubsidized solar PV is or may soon be a justifiable investment, but that market arrangements may play a crucial role in determining success. We end by sketching a proposal that amounts to a reformed capacity market that would afford participation of solar PV.**

***Index Terms*—solar PV, solar penetration, renewables penetration, curtailment, capacity market, solar investment**

I. Introduction

The generation of electricity from renewable resources has increased in the last decades, both in the U.S. and in Germany and indeed world-wide. In the U.S., renewables (other than hydroelectric) accounted for 7% of the overall electricity production in 2016 [1]. In Germany, the share of (non-hydro) renewable production increased from 6.2% in 2000 up to 31.6% in 2015 [2]. This increase was mainly caused by direct subsidies (mainly feed-in tariffs in Germany and the U.S.) or indirect subsidies (e.g., renewable portfolio standards and investment tax credits in the U.S.). In Germany direct subsidies (feed-in tariffs) were first implemented by the Renewable Energy Act in April 2000 [3]. This raises the question of renewables integration into the market. Currently, Germany follows a tendering approach for renewable generation larger than 750kW. The recent auction resulted in average subsidies of €0.0566/kWh for solar, €0.0428/kWh for wind on-shore, and €0.0044/kWh for wind off-shore [4].

These developments bring to the fore the question of whether variable renewable energy (VRE) generators can operate without subsidy and what market arrangements will be needed for them to work at significant levels of penetration. We focus on certain aspects of the problem. Specifically, this paper addresses what we call the *investment question*: Under what plausible circumstances, if any, can VRE generator (solar photovoltaic (PV) in particular) be a good investment? We look at both costs and market structures using high-level modeling to gain insight into whether a basic business case can be made for merchant, unsubsidized solar PV generators.

In the next two sections we describe the basic setups we investigate and then we provide some necessary background that serves to contrast our approach with the usual approach in the literature. We then employ solar insolation and market price data from the U.S. and from Germany to gain insight into the investment question. We find unsubsidized solar PV is or may soon be a justifiable investment, but that market arrangements may play a crucial role in determining success. We end by sketching a proposal that amounts to a reformed capacity market to afford the participation of solar PV.

II. Considered Setups

We explore in this paper three setups for estimating investment values of solar PV. In the first, a solar farm bids into the local day-ahead market. We use day-ahead market prices data from PJM (http://www.pjm.com), along with 20 years of solar radiation data (1991–2010) from Philadelphia International Airport (PHL, located within PJM's service area) [5].[1] In the second setup, a solar farm bids into the local real-time (spot) market. Again, we use the 20 years of solar radiation data from PHL, along with real-time (spot) market data from PJM, and recent German spot market prices.

Our third setup explores an idea recently raised in [6]. Solar power is normally and traditionally classified as VRE. Properly so, given it varies drastically from day to night, during daylight hours, between days in a year, and between years. Solar PV is also normally judged to be nondispatchable. As [6] points out, however, if a solar farm would by default withhold a certain fraction of its potential output at a given time, the realized output could be smoothed by removing the holdout to at least partially undo the effects of off-plan shortage of sunlight. Further, if greater than planned solar radiation is available, and the grid requires additional power, removing the default holdout would also help balance the grid. Much of the electricity produced under such a management regime can be sold with assurance of its availability, even years ahead of time. As such it can be framed as contributing capacity to the electric power system. This opens up the prospect of it being sold on new markets, beyond the day-ahead and real-time markets. We find the idea intriguing; [6] calls it "dispatchable

[1] We note that the data we use and nearly all of the data in the NSRDB is modeled data. During this period there were only 40 sites in the U.S. that took insolation measurements for NREL. These sites are scattered and often their data is quite incomplete.

solar with variable supply of electricity" (DSVSE). Here, we greatly extend the analytics given in [6]. We explore all three prospects in the sequel.

In all three setups, we make simplifying assumptions, including that of 0 marginal costs for the solar PV farm, which is standard in the literature and comfortably handled by further sensitivity analysis.

III. Background: Market Value

The *market value* of energy is a standard and widely-used metric for evaluating whether or not a method of electricity generation is, or can be, profitable (see [7]–[9]).

In the usual setup for market value analysis, a generator of type c (comparison generator) is compared to a base load (constant output) generator, type b. Both generators are assumed to obtain their revenues via participating in a (common) day-ahead market for a number of periods (typically, the 8760 hours over a year).

The *base price*, p^b, is the time-weighted average of the day-ahead prices. Mathematically, it is

$$p^b = (\mathbf{p}'\mathbf{1})/(\mathbf{1}'\mathbf{1}) \tag{1}$$

where $\mathbf{1}$ is a column vector of 1s with length of the number of periods under consideration (e.g., 8760 for a year). $\mathbf{p}$ is a column vector of day-ahead prices, with $\mathbf{p}$ and $\mathbf{1}$ having conformable lengths. p^b is the base price, the average price realized by a perfect base load generator.

The *comparison price*, p^c, is the time-weighted average of the day-ahead prices *received by a comparison generator*. Mathematically, it is

$$p^c = (\mathbf{p}'\mathbf{g})/(\mathbf{g}'\mathbf{1}) \tag{2}$$

where $\mathbf{p}$ and $\mathbf{1}$ are as above, and $\mathbf{g}$ is a vector of generator factors (by period), such that $\mathbf{g}'\mathbf{1}$ is the total generation over the time period (e.g., a year) and $\mathbf{p}'\mathbf{g}$ is the total revenue over the time period. p^c is the comparison price, the average price realized by a comparison generator.

Finally, the *relative market value* of a comparison generation method, c, is the ratio of the comparison price to the base price.

$$v^c = \frac{p^c}{p^b} \tag{3}$$

(p^c may be taken as the absolute market value of c.) Values of v^c above (below) 1 indicate that the comparison generator is more (less) profitable than a base load generator (having constant production throughout the period investigated). In the case of solar PV with time steps of an hour, taken for a year, most of the entries in $\mathbf{g}$ will be 0. Even so, it is entirely possible (and has been reported) that v^c values may be higher than 1.0, making solar generation profitable in light of the relative market value criterion (and unprofitable if below 1.0).

There is an extensive literature that uses market value analysis to gain insight into the question of whether, and if so under what conditions, VRE sources such as wind and solar can complete successfully on economic grounds (and without subsidies) with conventional generation. See references cited above for an entrée to the relevant literature.

A shortcoming of market value (absolute or relative) as an indicator of profitability, actual or potential, is that it neglects the costs of the generator, both its fixed and its variable costs. As seen above in the mathematical formulations, market value only takes into account revenues from generation of electricity (as sold into the day-ahead market). A case can be made for neglecting the variable costs of VRE (and in particular solar PV) because they are so close to zero. We avail ourselves of this approximation in what follows.

A case can also be made for neglecting the fixed costs of generators with the assumption that the producer surplus appropriated for them suffices (as it often has in the past) to cover the fixed costs [10]. This is increasingly a problematic assumption, which has been addressed in the literature and in practice by adding capacity or forward markets for the purpose of allowing at least some generators to recover their fixed costs outside of the day-ahead market. PJM notably has embraced this approach, while other service areas, e.g., Germany and California, have not.

We wish to take a different stance and explore the investment question of VRE, and in particular solar PV, taking into account an accurate assessment of the fixed costs. Our *investment* (or engineering economic) stance asks the question: Under what plausible circumstances, if any, can VRE (and solar PV in particular) be a good investment?

IV. Results: Solar Radiation Variability

We are content for present purposes to neglect sub-hourly variability of insolation and concomitant solar farm output. This is in any event standard in the literature. We do wish to focus on variability intra-day, inter-day, and inter-year. Our solar insolation data set affords this. In the interests of conserving space, we limit our examination of variability per se to just two regions: greater Philadelphia and Puerto Rico. Finally, we note that the underlying data we use in this section is for solar radiation received on a horizontal surface ('METSTAT Glo (Wh/m**2)'; see [5]). This is an underestimate of what a properly tilted PV panel would receive, but for our purposes of estimating the variability we stick with this conservative estimate.

A. The Greater Philadelphia Region

We calculate the hourly means over 20 years (1991–2010) of solar radiation (insolation) in Watts per meter^2, then total these hourly means as Total Annual shown in Table I. In the case of comparing 2 or more locations together, e.g., locations 2, 3 and 4 labeled (2,3,4) in the table, we first develop a mean insolation array from the several location arrays, and then average it as in the single location case. We do this for five different locations in or near Philadelphia, Pennsylvania, USA, as well as the combinations of these five locations. See Table I. In addition, we repeat this calculation using the hourly minimums over 20 years, instead of the means. (The NSRDB data we use [5] is modeled data, given as watts per square meter by hour. The hourly minimums, as we define them, are the smallest watts per square meter value over 20 years, one for each hour of the year.) We sum these up for the various combinations of locations and report it as Minimum Annual in Table I.

Ratio in the table is the ratio of (Minimum Annual)/(Total Annual) and represents the portion of the full production over the 20 years that would be achieved in the worst case of realizing the minimum observed insolation for each hour.

TABLE I
LOCATION KEY: 0:'ATLANTICCITY',1:'PHL',2:'PHILANE', 3:'WILKES-BARRE', 4:'ALLENTOWN'. TOTAL ANNUAL IS THE SUM FOR 8760 HOURS OF THE HOURLY 20-YEAR MEANS OVER THE MEANS OF THE LOCATIONS IN THE LOCATION COLUMN. MINIMUM ANNUAL SUBSTITUTES THE HOURLY 20-YEAR MINIMUMS FOR THE 20-YEAR HOURLY MEANS OVER THE MEANS OF THE LOCATIONS IN THE LOCATION COLUMN, SUMMED UP FOR 8760 HOURS. RATIO IS THE RATIO OF (MINIMUM ANNUAL)/(TOTAL ANNUAL).

Location	Total Annual	Minimum Annual	Ratio
(0,)	2718006	1180341	0.434
(1,)	2690098	1171072	0.435
(2,)	2665915	1167128	0.438
(3,)	2578335	1142994	0.443
(4,)	2624576	1163225	0.443
(0, 1)	2704052	1225996	0.453
(0, 2)	2691960	1225176	0.455
(0, 3)	2648170	1211116	0.457
(0, 4)	2671291	1219938	0.457
(1, 2)	2678006	1228050	0.459
(1, 3)	2634216	1212288	0.460
(1, 4)	2657337	1218473	0.459
(2, 3)	2622125	1214072	0.463
(2, 4)	2645245	1224632	0.463
(3, 4)	2601455	1209725	0.465
(0, 1, 2)	2691340	1243212	0.462
(0, 1, 3)	2662146	1231805	0.463
(0, 1, 4)	2677560	1237594	0.462
(0, 2, 3)	2654085	1234891	0.465
(0, 2, 4)	2669499	1240853	0.465
(0, 3, 4)	2640306	1231181	0.466
(1, 2, 3)	2644782	1238264	0.468
(1, 2, 4)	2660196	1240902	0.466
(1, 3, 4)	2631003	1230813	0.468
(2, 3, 4)	2622942	1235479	0.471
(0, 1, 2, 3)	2663088	1245556	0.468
(0, 1, 2, 4)	2674649	1249325	0.467
(0, 1, 3, 4)	2652754	1239894	0.467
(0, 2, 3, 4)	2646708	1243750	0.470
(1, 2, 3, 4)	2639731	1244458	0.471
(0, 1, 2, 3, 4)	2655386	1248535	0.470

For PHL, location (1,), summing the mean values over 8760 hours we get 2690098 watts of insolation per square meter, which is the average total annual insolation realized over the 20 years. Summing the 20-year minimum values over 8760 hours we get 1171072 watts of insolation per square meter. This serves as a floor for guaranteeing production of solar electricity. The ratio of the two values is 0.435. In other words, quite remarkably we think, a solar farm could withhold $(1 - 0.435) = 56.5\%$ of its production (un-withholding as necessary) and promise to deliver the hourly minimum values by hour as estimated by the 20-year history.

We note that there is a modest smoothing effect evident in the Philadelphia data. The ratios for the five single locations are generally below the ratios achieved by combining several location. Interestingly, both (2,3,4) and (1,2,3,4) achieve the highest ratios (and hence best assured supply). It would appear that this is just another way in which Atlantic City is problematic.

TABLE II
LOCATION KEY: 0:'AGUADILLA',1:'MERCEDITA',2:'SAN JUAN INTERNATIONAL AIRPORT'.

Location	Total Annual	Minimum Annual	Ratio
(0,)	2746275	1729864	0.630
(1,)	2872763	1182034	0.411
(2,)	2743047	1637812	0.597
(0, 1)	2809519	1582986	0.563
(0, 2)	2744661	1794294	0.654
(1, 2)	2807905	1524207	0.543
(0, 1, 2)	2787362	1673467	0.600

B. Puerto Rico

The analysis for Puerto Rico is fundamentally the same as that for Philadelphia. We do note that Aguadilla combined with San Juan assures the highest level of supply—ratio of 0.654—among the combinations identified here. See Table II.

V. RESULTS: ANALYSES OF SETUPS

A. Costs to be Recovered

It is common to use levelized cost of energy (LCOE) to assess and compare electricity generators. As is well known, LCOE neglects to a large degree the variability or necessary timing of the source it measures (it does factor in discounted timing of production). This is quite obviously a concern when evaluating VRE sources and solar PV in particular.

Given this, LCOE is a poor measure for evaluating a business case for solar. What we need is to evaluate the performance of a solar PV facility in an actual market (or reasonable facsimile thereof). Much as an investor would back-test a trading strategy by seeing how it would have performed in a suitably long period of time in the actual markets, so we use 20 years of solar radiation data to drive solar farm output and then we compare this performance with prices in markets over various years. This yields a much more robust, convincing picture than simply a single or even average year.

This accounts for the revenue from the markets. In order to see if the revenue is sufficient for a positive business case, we need to see if it yields a profit. Instead of LCOE, which we think is largely irrelevant at this point in the analysis, we model the annualized cost of building and running the solar farm. We assume a 25-year economic life for the farm (of course this can be varied in the analysis, but we find it does not matter a lot) and an interest rate, or hurdle rate for the project. This would include both the cost of capital (a loan or sale of bonds, for example) and a required rate of return (profit in the businessman's sense). The capital cost of the project is the sum of the construction cost (including materials, labor, land, permitting and inspection, and so on) plus the present value of the operations and maintenance cost over the economic life of the farm (including cleaning, replacement of inverters, etc., but of course not fuel). Together this is the present value of the cost of the farm. Given all this, we can calculate the annual cost of the farm, as the annual loan payment required to retire a loan for the present value of the cost of the farm. There is a well-known engineering economics formula for this (using the *capital recovery factor*, aka *AgivenP*). Given an initial capital outlay of P, an interest rate of r ($= 0.03$ for a 3% rate, e.g.) and a project lifetime of n periods (years), the annualized capital cost is $P(r(1+r)^n)/((1+r)^n - 1))$. In Table III we see a sensitivity analysis on the present cost and interest rate, fixing the economic life at 25 years, and assuming that the entire present cost is funded with a 25-year loan at this interest rate. We shall advert to this table in the sequel.

TABLE III
ANNUAL PAYMENTS OVER 25 YEARS FOR A 1 MEGAWATT SOLAR FARM HAVING PRESENT VALUE P IN MILLIONS AND HURDLE RATE r.

	r					
P	0.030	0.048	0.066	0.084	0.102	0.120
0.60	34457	41722	49645	58140	67120	76500
0.80	45942	55630	66193	77520	89493	102000
1.00	57428	69537	82741	96900	111866	127500
1.20	68913	83444	99290	116280	134240	153000
1.40	80399	97352	115838	135660	156613	178500
1.60	91885	111259	132386	155040	178986	204000
1.80	103370	125166	148935	174420	201360	229500
2.00	114856	139074	165483	193800	223733	255000
2.20	126341	152981	182031	213180	246106	280500

Reported P (present value) costs for solar PV are changing (declining), competitive with traditional generation (e.g., [11]), and are forecast to decline in the future. Several sources in the U.S. have indicated \$1/watt installed for "utility scale" P, and the Department of Energy's SunShot project aims for \$0.50/watt by 2030. We conduct our analysis in terms of P values for 1 megawatt (MW) of capacity, and will interpret the table accordingly.

Finally, we note the role of leverage. To illustrate, assume investment for a 1 MW farm with P = 1.2 (million). The investor puts up 0.2 million in capital and borrows the remaining \$1.0 million at an interest rate of 4.8% (0.048 in the table). The annual payments to the lender would then be \$69537. Suppose the actual return (on average) is \$96900 or 8.4%. The investor earns $(96900 - 69537)/200000$, amounting to an annual return of 13.6% on capital invested.

B. PHL Day-Ahead Market

Focusing now on PHL insolation data, Table IV shows what the revenue of a 1 megawatt capacity solar PV farm would be from the (hourly) PJM day-ahead market of 2010.

We note, for here and the sequel, that the amount of solar radiation will affect demand and prices. We neglect this and permit ourselves to see how a solar farm receiving radiation in one year would perform against prices in another year. Also, we neglect line losses and congestion charges.

Drawing on Table III, we see that on average (for the mean revenue) the project is profitable or nearly so only for a narrow range in the table. Roughly for $P \leq 1.2$ and $r \leq 0.102$, there are a number of $P - r$ combinations that are profitable. Some of these combinations are realistic today; others are expected to be feasible in the near future. (Recall the SunShot goal of $P = 0.50$.) This is, again, assuming PJM day-ahead prices obtaining in 2010, which have since deteriorated. Note as well that in using the 'METSTAT Glo (Wh/m**2)' data, we are underestimating the amount of solar PV production. Nor are we including investment tax credits and other incentives.

TABLE IV
PHL 1991–2010 SOLAR RADIATION WITH 2010 DAY-AHEAD HOURLY PRICES. MEAN REVENUE = 69900.

Year	Revenue in \$U.S.
1991	73767
1992	68381
1993	74018
1994	72605
1995	72447
1996	74913
1997	72512
1998	70068
1999	70220
2000	71113
2001	74008
2002	74404
2003	64590
2004	68084
2005	69393
2006	65497
2007	67494
2008	66738
2009	61343
2010	66413

C. Real-Time (Spot) Market

Table V is analogous to Table IV, but it substitutes 2016 German real-time prices for 2010 PJM day-ahead prices. The German 2016 spot prices (which are fairly close to the 2016 PJM prices) are generally lower than the PJM 2010 day-ahead prices and so there is less scope for profitable investment. This is exacerbated by our assumption of PHL insolation levels, which are very likely above anything in Germany, but we make do with the data we have. In consequence, there is only a small region of Table III that would make solar investments attractive. But if not feasible today, the near future is promising.

Table VI resembles Table V, but with PJM real-time prices for 2010 substituted for the German 2016 prices. The main thing is that the returns using the PJM 2010 real-time prices, in Table VI, are quite similar to the returns using the PJM 2010 day-ahead prices, in Table IV, and so would indicate an interesting investment prospect. We repeat that prices change and the PJM prices in 2016 are closer to the German prices.

D. DSVSE Regime Analysis

The DSVSE idea, broached in [6], envisions partitioning the output of a solar PV farm into two components, which we may call the variable and the assured components. To produce the assured component, a withholding level is set for an entire

TABLE V
PHL 1991–2010 SOLAR RADIATION WITH GERMAN 2016 SPOT MARKET HOURLY PRICES. ASSUMING 1 €= 1.25 $U.S. MEAN REVENUE = 48525.

Year	Revenue in $U.S.
1991	50396
1992	46941
1993	50290
1994	50860
1995	50263
1996	50889
1997	50613
1998	49494
1999	49026
2000	50068
2001	51630
2002	50810
2003	45695
2004	47464
2005	48752
2006	45595
2007	46159
2008	46260
2009	42973
2010	46331

TABLE VI
PHL 1991–2010 SOLAR RADIATION WITH PJM 2010 SPOT MARKET HOURLY PRICES. MEAN REVENUE = 71986.

Year	Revenue in $U.S.
1991	75883
1992	70556
1993	76696
1994	75170
1995	74155
1996	77499
1997	74930
1998	72095
1999	72565
2000	73396
2001	76373
2002	76376
2003	66347
2004	70094
2005	71251
2006	66866
2007	69654
2008	68701
2009	62766
2010	68346

year on an hourly basis. If, for example, the commitment in hour h is for level 0.34 megawatts, then the solar farm sends the 0.34 megawatts (for the hour) to the customer (utility or some other party). This is the assured electricity. If there is insolation sufficient to produce in excess of 0.34 megawatts during the hour, the farm is free to deliver the excess to another party, including the day-ahead and spot markets. This amount is the variable amount for that hour.

What if insolation is insufficient for 0.34 megawatts, i.e., for the level of commitment for assured electricity? Risk and penalty calculations can be made when originally committing to the 0.34 megawatts, but perhaps the simplest regime, and the one we investigate, is to look at the historical record and commit for the hour the smallest amount generated over the record, e.g., over the 20 years of insolation data we have.

How might such a regime be financially attractive? [6] comments that the assured electricity might command a higher price, while the variable electricity could receive a normal price, e.g., through the spot market.

The effect of such a scheme is, as noted above, to partition the solar farm's output into two categories, which we will call variable and assured electricity. Slight reflection shows that the partitioning has no effect on the total revenues of the farm, provided both categories receive the same price and provided that the administrative costs (switching, etc.) are negligible.

Comparison of Tables IV and VII demonstrates the effect. Table VII splits the revenue (with common prices) into variable revenue and assured revenue, using the hourly minimums of the solar data, used in Table I for PHL. Their sum, in the Total Revenue column, matches the revenue column of Table IV.

TABLE VII
BREAKOUT OF VARIABLE ENERGY REVENUES AND ASSURED ENERGY REVENUES (IN $U.S) FOR PHL 1991–2010 SOLAR RADIATION WITH PJM 2010 SPOT MARKET HOURLY PRICES. MEAN VARIABLE REVENUE: 44220.

Year	Variable Revenue	Assured Revenue	Total Revenue
1991	48087	25680	73767
1992	42701	25680	68381
1993	48339	25680	74018
1994	46925	25680	72605
1995	46768	25680	72447
1996	49233	25680	74913
1997	46833	25680	72512
1998	44389	25680	70068
1999	44540	25680	70220
2000	45434	25680	71113
2001	48329	25680	74008
2002	48725	25680	74404
2003	38911	25680	64590
2004	42405	25680	68084
2005	43713	25680	69393
2006	39818	25680	65497
2007	41815	25680	67494
2008	41058	25680	66738
2009	35664	25680	61343
2010	40734	25680	66413

Table VIII considers the effect on assured revenue in this scenario of increasing the day-ahead prices by $0.01, $0.02, or $0.03 per0. kilowatt ('Plus1', etc.). Notice that the farm becomes economically more attractive with the assured electricity revenues, but the effect is fairly small. Other factors in the model, such as original cost and interest rate, matter more.

VI. Discussion and Conclusion

Spot and day-ahead prices somewhat higher than those we have examined, or somewhat lower costs (P), would make merchant solar PV a profitable business without subsidies or other incentives. Against this is the fact that spot and day-ahead prices are affected by the introduction of VRE. Because VRE has next to 0 marginal cost it is taken, when available, by the merit order (least marginal cost) rule in spot and day-ahead auctions. In consequence, introduction of VRE drives down the spot and day-ahead prices. The prospect then is that no one can make money and the market fails. This is a genuine

TABLE VIII
BREAKOUT OF VARIABLE ENERGY REVENUES AND ASSURED ENERGY REVENUES (IN $U.S) FOR PHL 1991–2010 SOLAR RADIATION WITH PJM 2010 SPOT MARKET HOURLY PRICES. MEAN VARIABLE REVENUE: 44220.

Year	Variable	'Plus 1'	'Plus 2'	'Plus 3'
1991	48087	30645	35610	40575
1992	42701	30645	35610	40575
1993	48339	30645	35610	40575
1994	46925	30645	35610	40575
1995	46768	30645	35610	40575
1996	49233	30645	35610	40575
1997	46833	30645	35610	40575
1998	44389	30645	35610	40575
1999	44540	30645	35610	40575
2000	45434	30645	35610	40575
2001	48329	30645	35610	40575
2002	48725	30645	35610	40575
2003	38911	30645	35610	40575
2004	42405	30645	35610	40575
2005	43713	30645	35610	40575
2006	39818	30645	35610	40575
2007	41815	30645	35610	40575
2008	41058	30645	35610	40575
2009	35664	30645	35610	40575
2010	40734	30645	35610	40575

problem. Both in Germany and in PJM there has been a decline in these prices due at least in part to VRE. (A reviewer also tells us that "Large solar plants in Chile (North System) have driven down electricity prices spectacularly, strongly affecting the business case of these plants.")

What can be done? We explored, above, the possibility of rewarding the assured portion of solar production with increased payments. The obvious question now, at least with regard to the variable-assured scheme just discussed, is: Why should the solar farm's assured electricity receive a price higher than the day-ahead price? Base load (constant output) coal and nuclear plants would surely object, and end-users would always have the option of buying with assurance from the utility company.

There is much to discuss with regard to this question and a set of options, including bilateral contracts in a commodities market (as practiced in Germany for example). We wish to conclude, however, by raising a quite fundamental question, calling for future research, indeed for much further investigation.

One answer to the "Why higher prices for assured solar PV?" question is to note that in some areas other, non-VRE, sources of generation already receive such payments through what is called a capacity or forward market [10], [12]. PJM uses one. The effect is to have the generator plants recover their fixed costs (or a portion thereof, enough to keep them in business) by committing 3 years ahead of time (in the case of PJM) to having available a certain amount of capacity. An auction is held and the winners can be assured of certain payments. They then participate in the day-ahead, etc. markets, which have consequently lower prices. PJM has done this since 2007.

The fact is, however, that capacity markets generally, and PJM's in particular, require bids of entire day uniform commitments. This is of course impossible for a solar PV farm. What to do? One suggestion is that the design of capacity markets should be reformed to afford participation with hourly commitments (some 0 if needed) that would effectively permit VRE plants to bid into the market if they were confident of being able to meet their commitments say 3 years ahead of time. Solar farms, having good historical insolation data and using the minimum insolation rule explored here, could be in position to do so.

To this end, consider the problem of an integrated utility seeking greenfield capacity planning. We propose a much simplified optimization model as a way of communicating our thought here. (The relevant literature is voluminous. See [13]–[15] for starters.)

In our model in its most basic form, there are three types of generators: base load x, mid-merit y, and variable renewable z (solar PV). Each type may be chosen 0 or more times. Each instance of a type, however, is identical with the others of the type. (The model can be expanded in obvious ways to include more types.) Decision variables: x^1 is the number of base load plants chosen, x^2 is the number of fixed costs for base load plants chosen, z^1 is the number of solar PV plants chosen and z^2 is the number of their fixed costs, y_i^1 is the number of mid-load, or load following, plants needed at period i, and y^2 is the number of fixed costs for the chosen load following plants.

The objective function is: $\min z =$

$$(a^1x^1 + a^2x^2) + (b^1\sum_{i=1}^{24} y_i^1 + b^2y^2) + (c^1z^1 + c^2z^2) \quad (4)$$

This is subject to

$$c_i^a x^1 + c_i^b y_i^1 + c_i^c z^1 \geq L_i, \quad \forall i \in \{1, 2, \ldots, 24\} \quad (5)$$

$$x^2 - x^1 \geq 0, \quad z^2 - z^1 \geq 0 \quad (6)$$

$$y^2 - y_i^1 \geq 0, \quad \forall i \in \{1, 2, \ldots, 24\} \quad (7)$$

$$x^1, x^2, y_i^1, y^2, z^1, z^2 \in \{0, 1, \ldots u\}, \quad \forall i \in \{1, 2, \ldots, 24\} \quad (8)$$

where L_i is the load or demand planned for period i. In this formulation we model one 24-hour period. a^1, b^1, c^1 are variable costs, and a^2, b^2, c^2 are fixed costs allocated to the day. c_i^a is the capacity or power delivered by a base load plant during hour i; c_i^b is the capacity or power delivered by a load following plant during hour i; and c_i^c is the capacity or power delivered by a solar PV plant during hour i. The model chooses a minimal cost configuration of the given types of plants, subject to meeting load requirements, and taking into account both fixed and variable costs of the plants. (MATLAB code available from the authors.)

Our suggestion is: This model (or something conceptually like it but with additional detail) (a) could be used by an integrated utility to do capacity planning and (b) could be used by an ISO as a basis for a capacity market accommodating VRE, with the solar PV configured to supply what we have called assured electricity. The plants bid their fixed and marginal costs, the ISO optimizes, plants that make the cut receive their fixed costs and are obligated to participate in the day-ahead market.

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