Discussion Paper: Addressing Intermittency with Dispatchable Solar and Variable Supply Electric Power Services

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October 6, 2017

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Abstract

As measured standardly by levelized cost of energy (LCOE), onshore wind and utility scale solar PV (photovoltaic) have been rapidly declining in cost and are now reported to be the cheapest ways of generating electric power. While this is indisputably a welcome development, the fact that renewables in general—wind and solar in particular—are variable and available only intermittently makes LCOE a quite incomplete, perhaps even misleading, measure of value because it neglects the system cost of accommodating renewables for the sake of meeting demand and keeping the grid in balance. The additional cost of building and employing peaker plants (mainly fueled by natural gas), which serve as backup and reserve and hence are often idle, has led many observers to pessimistic conclusions about the economic viability of very high levels of penetration by renewable sources of energy.

This paper fully acknowledges the problem. We present an ensemble of several ideas that plausibly may be useful for mitigating the intermittency problem accompanying high levels of penetration of renewable power generation, particularly solar PV (photovoltaic). The ensemble, presented as a proposed setup or institution, includes provision for dispatchable solar PV (and by extension wind power) as well as provision for a market for what we call *variable supply electric power*. This is described in the paper and contrasted with existing services, which may be described as *guaranteed supply*. Further, we confront our proposed setup with three years of insolation data for Philadelphia, PA. This leads to a number of quantified measures of variability that should be useful for system design and management.

This is an exploratory paper, aiming at an initial vetting of these ideas. Very much remains to be done to investigate them fully.

1 Introduction

The growth in deployed renewable generation of electric power (especially from wind and solar PV—photovoltaic) is well known to have been quite rapid during the last few years, both in the developed world and in emerging economies. This is occurring in parallel with rapidly declining costs for utility scale solar PV and onshore wind (among other configurations). In consequence of these cost reductions, a number of credible studies now find that, measured on levelized cost of energy (LCOE) and without subsidies, onshore wind and utility scale solar PV are now the cheapest means of generating electric power, cheaper than fossil fuels and nuclear plants (Lazard, 2016).

All this is well and good. It is most welcome and it warrants a degree of optimism that the world will successfully make an *Energiewende*, an energy transition to renewable sources of energy. However, while (some) optimism is warranted, any belief that the main problems are well on their way to solution is not so warranted. The fact remains that renewables are variable—they are said to be *intermittent*—and the electric grids we use to distribute power need to be kept in close balance. LCOE does not attempt to measure the cost of accommodating variability and intermittency. That very considerable cost remains a serious challenge when we contemplate high penetration levels of renewables.

We fully acknowledge the problem and grant its force. In this paper, we present an ensemble of several ideas that plausibly may be useful for mitigating the intermittency problem accompanying high levels of penetration of renewable power generation, particularly solar PV. The ensemble, presented as a proposed setup or institution, includes provision for dispatchable solar PV (and by extension wind power) as well as provision for a market for what we call *variable supply electric power*. This is described in the paper and contrasted with existing services, which may be described as *guaranteed supply*. Further, we confront our proposed setup with three years of insolation data for Philadelphia, PA. This leads to a number of quantified measures of variability that should be useful for system design and management.

The longer-term challenge of high penetration can be contrasted with the present rapid growth of deployed renewables. When highly variable sources of electric power are used to supply a grid in relatively small amounts, the net variability can often be neglected or managed easily and cheaply. Such is the situation today in large part, with solar and wind constituting, typically, at most a small percentage of the total power generated for any other than small length of time. As renewables increase their penetration, the problems—particularly the costs of using peaker plants—increase greatly. Widespread reporting has it that 30–40% penetration of renewables is the upper limit of what can safely be accommodated without risking grid destabilization (of course, this depends on available storage and other configuration matters). PJM (`http://www.pjm.com`), for example, has recently reported, remarkably, that it can have up to 86% of the power in its domain supplied by natural gas generators without risking grid destabilization. (Here the issue is destabilization due to supply shortages of natural gas; if the gas is available, then the gas-fired generators are quite capable of sustaining the grid.) Further, PJM asserts that it can have up to 20% of its power sourced from renewables, without destabilizing the grid. (A fair portion of the 20% would be hydroelectric power, which has a stabilizing effect but is limited in availability.) PJM concludes that it can, if it had to, eschew both coal and nuclear as sources of electric power (PJM Interconnection, 2017).

All of this represents cause for optimism regarding the *Energiewende,* but it hardly negates our point that recent increases in penetration of renewables are not projectable very far and do not represent any serious addressing of the variability problems associated with achieving very high penetration levels.

We wish, in this discussion paper, to present concretely something of the magnitude of the intermittency problem as it pertains to deep penetration of renewables. We do this by exploring insolation data for the Philadelphia, PA region across three years. We find a very high degree of variability, even when we focus on a single hour (hour 12) of the day throughout the year. In response we propose and begin to explore an institutional response to the problem, one that combines curtailment and production for a variable supply service market for electric power. We find this approach promising, although the analysis here cannot be close to dispositive.

The remainder of the paper is organized as follows. §2 briefly provides essential background and context for the variability problems in electric power systems, and what can be done to mitigate these problems. Solutions are available; the challenge is to find economic (minimal cost) solutions. That challenge is exacerbated greatly by renewables. §3 presents an initial look at the data for Philadelphia insolation. It demonstrates the problematic variability of this insolation. §4 describes and sketches our envisioned setup for addressing stability and provision challenges associated with intermittent solar PV. §5 revisits the data in the context of our proposed setup with the aim of gaining insights into the setup's viability. §6 summarizes and concludes with comments on future research.

2 Background

Variability is costly. Insurance, hedging, portfolio diversification, and futures contracts are, among others, all widely used institutions for paying to ameliorate the consequences and costs of variability, arising in multiple contexts. The problem is especially acute in the case of electric power systems, which have to be kept in balance over short periods of time (a few seconds to several minutes (Ellison et al., 2012)) in the presence of fluctuating demand. Because electric power systems are not purely financial entities, handling variability eventually comes down to manipulating physical components. There are in principle only a few kinds of options for managing the physical aspects of variability in electric power systems:

1. Storage. Hydroelectric systems, electric batteries, compressed air, super capacitors, thermal reservoirs, etc. are examples of storage mechanisms important in electric power systems.

2. Demand management: shifting or reducing demand. Demand response, either negative (curtailing and/or shifting demand at times of high load) or positive (adding load during times of surplus supply; also called *reverse demand response* (St. John, 2016)), and dynamic pricing (encouraging demand at times of low load) are two expedients used in electric power systems.

3. Diversification. Using long distance transmission lines to exchange power with distant markets and employing multiple sources of power (e.g., both wind and solar) are examples in electricity markets.

4. Supplementary investment and production. These are called ancillary services in electric power provision. They include spinning reserves, generating capacity with fast start up, and so on. It is common and useful to distinguish between *base load generation plants* and multiple types of *peaker plants*. Base load plants (e.g., coal, nuclear) produce electric power at more or less constant rates that can be varied under control only modestly and slowly at that. Peaker plants, typically using natural gas as fuel, are drawn upon when available base load generation is insufficient for current

demand. They are also amenable to controlled variable output, much more so than coal and nuclear.

Each source of variability reduction has its own costs, which are often high, as well as its own operating and availability characteristics, thereby greatly complicating system design and operation.

The problem of managing variability in conventional (fuel-based) electric power systems arises because demand (load) is variable. Design of conventional electric power systems involves a careful tradeoff and optimization between base load plants, which are cheaper per unit of power produced if they are kept operating most of the time (e.g., coal, nuclear) but are inflexible, and peaker plants, said to be highly dispatchable because they can be made responsive to fluctuations in demand, but at the cost of idling capital when demand is absent.

Variability is exacerbated when the supply of power is also variable. Conventional sources of supply, such as coal, natural gas, hydroelectric, and nuclear plants, afford steady supply of power. This changes with the introduction of renewable energy sources, raising the important question of how, at what cost and at what level, renewable energy sources can be incorporated into electric power systems and, in any event, putting a premium on the flexibility associated with peaker plants, which serve to take up the slack when renewables are in low supply. (See (IEA, 2014) for a thorough and thoughtful discussion of the issues involved.)

It is well known that solar PV supply is highly variable, even during the day. Figure 1 illustrates for Philadelphia, PA, showing very high daily variability in insolation during a typical meteorological year (TMY; TMY data is available at `https://energyplus.net/weather`.) This is true even in such solar PV favorable circumstances as Saudi Arabia. Figure 2 illustrates. In both cases, if we were to zoom in and look at the variation by hour, the variability would appear even more problematic.

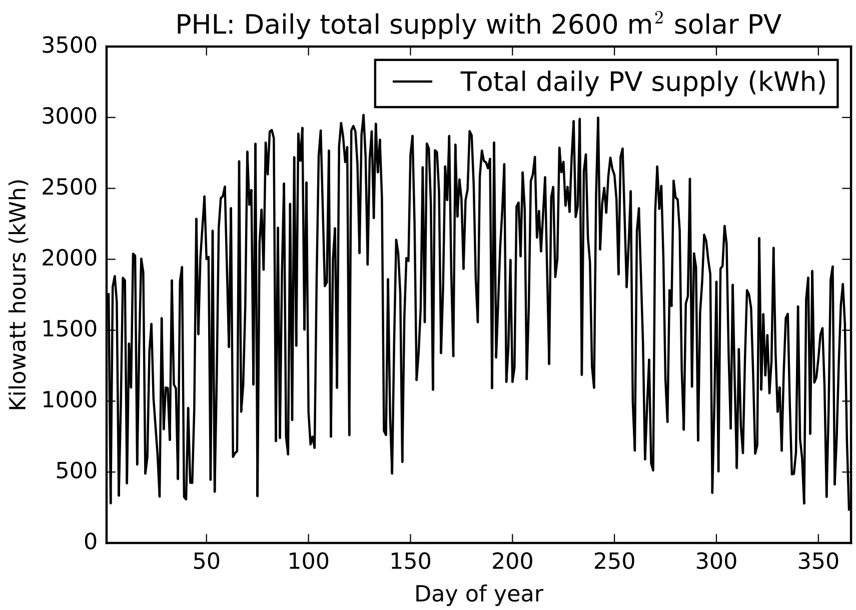

Figure 1: Total daily supply over 365 days with 2600 m^2 solar PV installed for Philadelphia, PA, in a typical meteorological year.

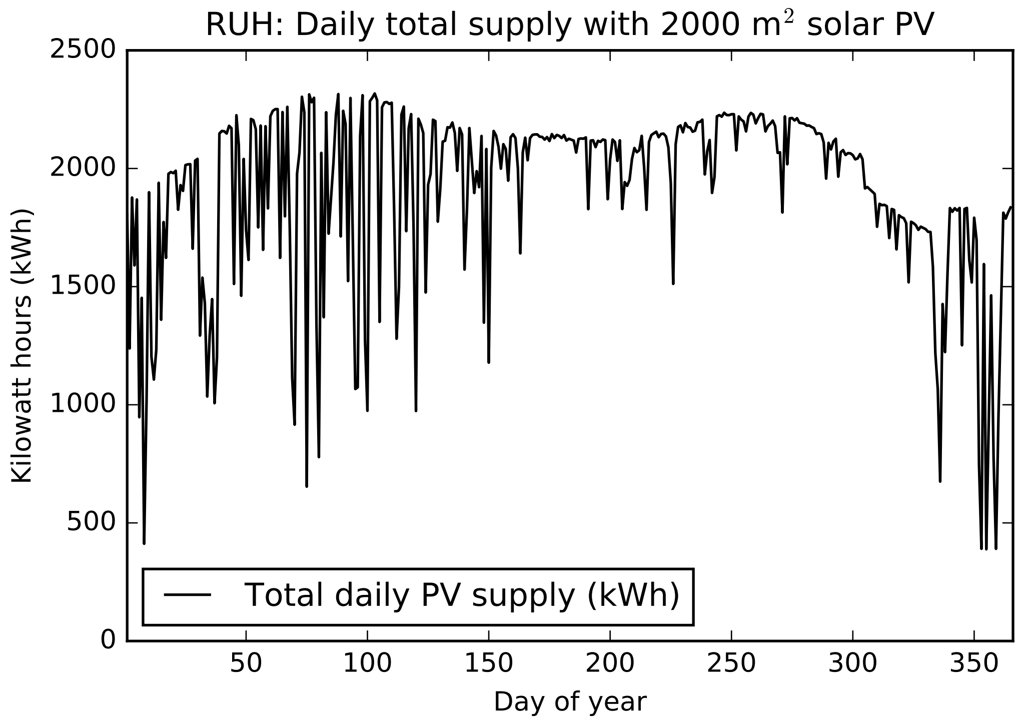

Figure 2: Total daily supply over 365 days with 2000 m^2 solar PV installed for Riyadh, Saudi Arabia, in a typical meteorological year.

In Figure 3 we do that, looking at daily insolation in Philadelphia for hour 12 (11:00–12:00) during 2015.

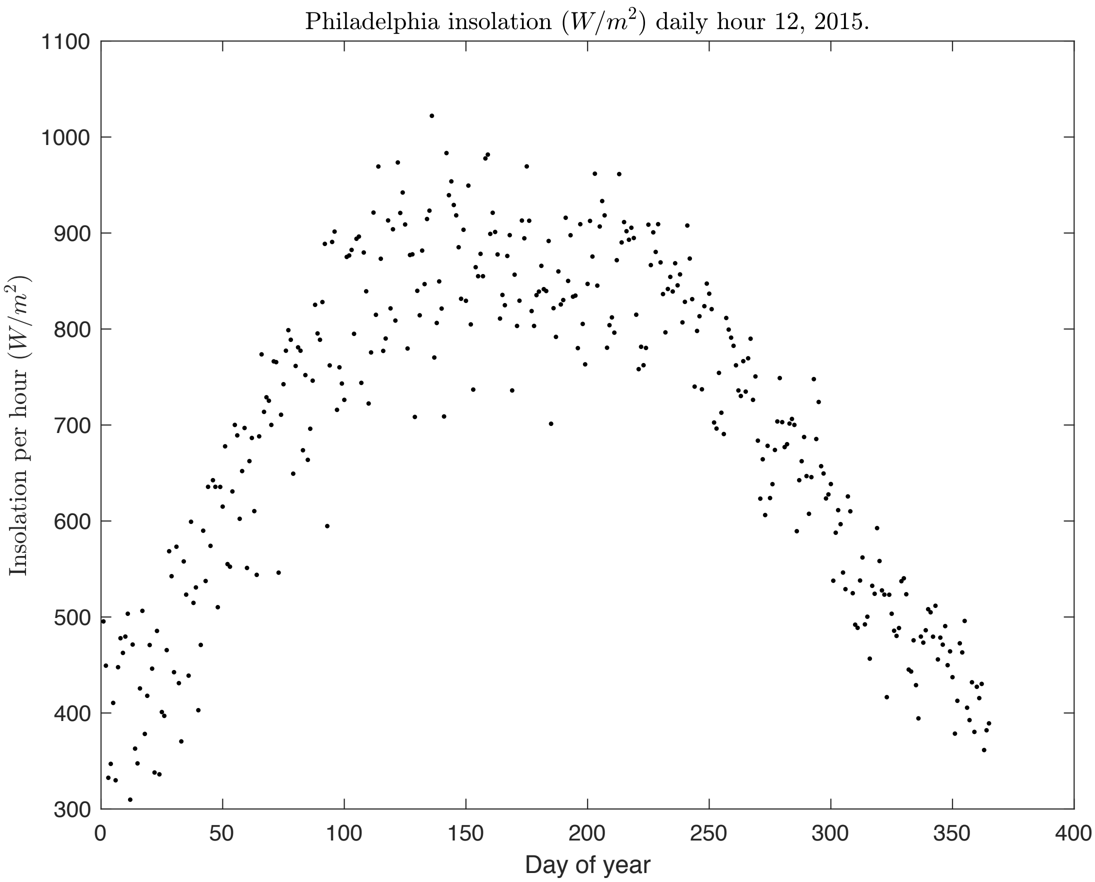

Figure 3: Philadelphia noon hour insolation, 2015.

Notice the high daily variability in solar energy (insolation) received during the noon hour over the year. As we shall see, 2015 was a comparatively *favorable* year for solar PV in Philadelphia. This is a serious problem for using renewable energy sources, in particular solar photovoltaic (PV), for generating electric power. This discussion paper is about exploring the nature and extent of that variability and what might be done to mitigate the problem so that higher levels of renewable energy can be used economically in the electric power system.

Renewable energy sources, such as solar and wind power, are said to be *intermittent* because they are not continually available, even approximately so. Their availability varies with time of day, with day of the year, and with local weather conditions. This elemental fact raises fundamental challenges for incorporating high levels renewable energy sources into electric power systems, which must maintain supply and demand (load) balance at all times, within close tolerances. Were the cost of efficient electric storage negligible there would be no challenge, costs of the renewable sources themselves aside, for systems could be configured so as to provide real time availability to meet load demands from storage and to maintain an adequate buffer of storage to accommodate intermittent supply.

Alas, despite rapidly declining costs of solar energy, wind energy, and storage for electric power, integrating high levels of renewable energy sources and doing so at acceptable cost is a problem that will remain with us for the foreseeable future. This leads some authors, e.g., (Hall et al., 2014; Weißbach et al., 2013) to profoundly pessimistic conclusions about the future of renewable electric power. In any event, the prospect is for a continued need for careful design and optimization of heterogeneous energy systems if they are to be viable at all. These systems at least potentially incorporate renewable sources of electric power, fossil fuel sources (to be minimized insofar as possible), possibly nuclear, hydroelectric as well as other sources (e.g., geothermal, ocean waves), along with pricing regimes to encourage conservation and demand shifting (including demand response regimes), storage in multiple forms, and trade with regions in relative surplus or shortage (via transmission lines).

3 Data Overview

For the present discussion we focus on a rather special case, which nevertheless affords ample demonstration of the variability problems with solar PV: Philadelphia insolation during 2005, 2010, and 2015. (The years were chosen arbitrarily. The raw data were purchased from White Box Technologies (`http://weather.whiteboxtechnologies.com/`) and munged by us.) Further, we focus here on presenting data for a single hour of the day throughout the year: hour 12 (11:00–12:00), a generally favorable time for solar PV.

Figure 4 presents a full year summary of the hourly data (8760 hours per yer) for Philadelphia insolation, for years 2005, 2010, and 2015. What we see is that there is considerable daily variation across the year—entirely expected, but here quantified somewhat—

and that there is substantial variation by year, with 2015 being the sunniest of the three years and 2005 the least productive for solar PV.

```
phila = pd.read_csv('../data/WhiteBoxTechnologies/Processed/
philainsol051015.csv',index_col=0)

phila.shape
Out[10]: (8760, 3)

phila.describe()
Out[11]:
              2005         2010         2015
count  8760.000000  8760.000000  8760.000000
mean    162.325468   179.808368   215.467808
std     239.447334   253.505342   283.867349
min       0.000000     0.000000     0.000000
25%       0.000000     0.000000     0.000000
50%       8.750000     0.000000    13.000000
75%     267.500000   317.300000   423.150000
max     961.800000   947.600000  1022.100000
```

Figure 4: Full year summaries for Philadelphia insolation data, years 2005, 2010, and 2015. Quantities are in Watt hours per square meter. (Edited slightly for display.)

Figure 5 presents a full year summary of the hour 12 data for Philadelphia insolation, for years 2005, 2010, and 2015.

```
phila.loc[12:8760:24,:].describe()
Out[13]:
             2005        2010         2015
count  365.000000  365.000000   365.000000
mean   524.555616  572.924932   699.011781
std    239.894487  231.649625   174.004152
min    125.300000   78.300000   314.300000
25%    333.700000  391.000000   537.100000
50%    494.800000  580.100000   735.400000
75%    756.900000  779.500000   848.100000
max    961.800000  947.600000  1013.000000
```

Figure 5: Full year summaries for Philadelphia hour 12 insolation data, years 2005, 2010, and 2015. Quantities are in Watt hours per square meter.

Finally for now, Figure 6 plots the daily hour 12 insolation levels for the years 2005, 2010, and 2015. Clearly, there is much variation among the years, as well as within them.

We turn now to describing an institutional setup that may help ameliorate the variability problem so evidently present in these data.

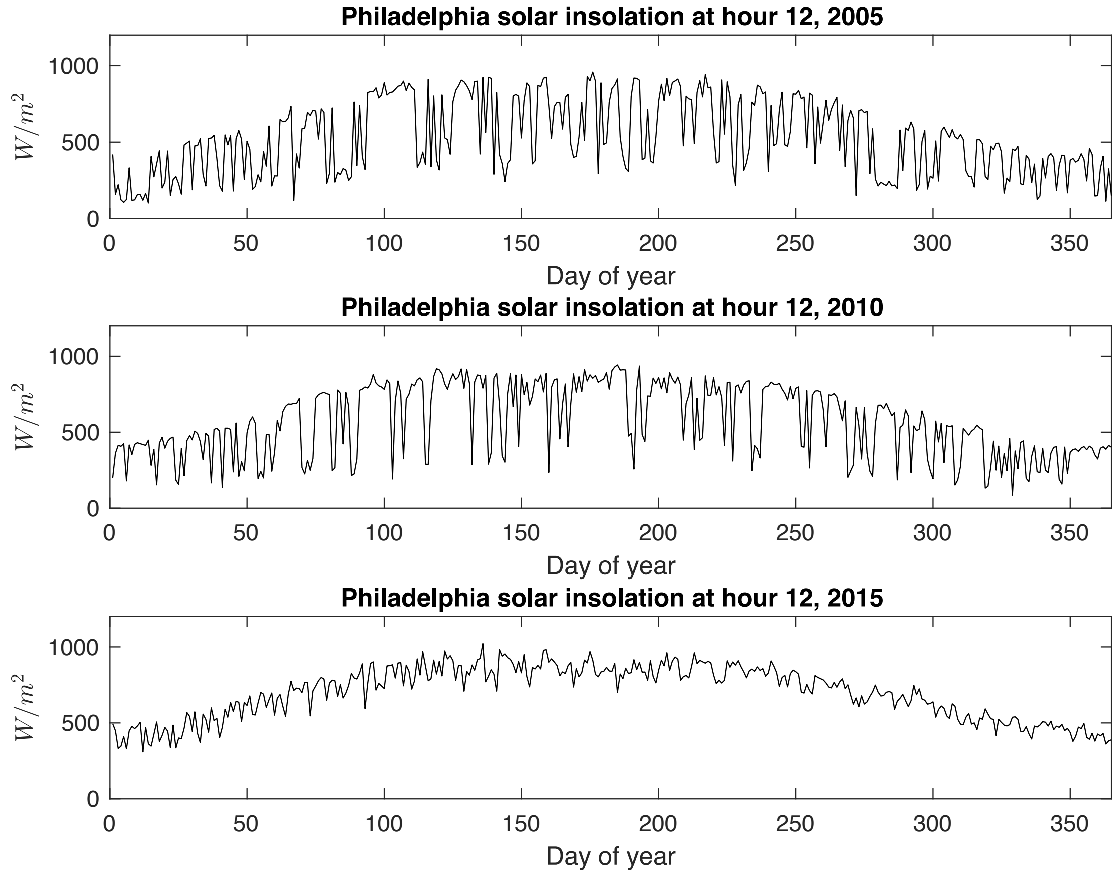

Figure 6: Three years of insolation during the noon hour in Philadelphia.

4 Envisioned Setup: Dispatchable Solar + Variable Supply

We are exploring a solar PV setup—really family of setups or institutional arrangements—with an eye to ameliorating the fundamental variability of insolation. We do this in hopes of gaining insights into how high penetration levels of renewables, particularly solar PV, may be accommodated. The design space is huge and goes well beyond the few factors we consider here, where our aim is to gain a certain amount of insight by examining a minimal arrangement, upon which other setups might build.

As indicated by its name—Dispatchable Solar + Variable Supply—there are two intertwined concepts are the core of the setup. First, regarding dispatchable solar, renewable sources of electric power, particularly wind and solar can be curtailed in detail (in increments). It is now standard to install such capability on wind turbines. It can be done with solar farms by wiring and switching them so as to open the circuits connecting panels (elements of the farm) to the grid (or other power sink). Once installed, this can be done rapidly and safely. Given curtailment of this sort, oversupply can be reduced easily, immediately, and even automatically. Further, to whatever extent a solar PV farm is being curtailed at any time, additional power can be dispatched from it (produced and directed to a destination) up to the amount that was being curtailed and subject to insolation conditions. (This holds for dispatchable wind as well.)

Second, regarding variable supply, we note that existing grids provide (in the main) only one kind of service: guaranteed supply. Up to the limits of the customer's configuration, the customer at any time may demand an arbitrary level of supply and the grid via the utility will meet the demand. Variable pricing schemes are often in place to encourage customers to behave in a grid-friendly way (e.g., by reducing demand at times of peak load), but for the most part guaranteed supply is the order of the day. Under a variable supply regime, which would constitute an electricity service distinct from and complementary to guaranteed supply, customers would contract for an amount of power to be taken over an agreed period of time. The following use case, in Figure 7, presents a specific example, which we trust will suggest to the reader many intriguing variations. There are three agents involved: the customer, the grid operator (utility company), and the solar PV farm.

With these points to hand we can describe a prototype for the kind of setup—Dispatchable Solar + Variable Supply—we wish to explore. The key points are as follows.

1. Given a solar PV farm that is to be attached to the grid, the utility uses the farm design and configuration as well as historical weather data to estimate annual power production from the farm. This estimate is for both day of year and hour of day. The utility fits a curve to the estimates, which of course are noisy. This curve is called the *base planning curve*.

2. Estimating the likely deviations that will occur, especially undersupply, the utility sets a default curtailment rate, e.g., 10%.

3. The farm agrees to operate with curtailment at the set default.

4. The utility organizes a variable supply service market, which the solar farm may participate in if it chooses (let us assume it does).

5. Any production by the solar farm in excess of the base planning curve is made available to the variable supply market.

6. If conditions are such that the farm's production is insufficient to meet the demands of the base planning curve, the utility must obtain power elsewhere and the farm pays a penalty, but may use excess power generated at other times to pay the penalty, pro-rated as appropriate.

1. The course of events begins when the customer commutes to work by electric vehicle and parks the car in a charging access enabled location.
2. The customer connects the vehicle to the charging apparatus.
3. A controller agent (software plus sensors, etc.) in the vehicle senses the amount of charge needed and the window in which it can be provided (say the next 3 hours; information provided by the driver), and communicates this to the controller agent for the grid operator.
4. The grid operator (controller agent) notes the request, consults the state of the grid, consults the solar farm and finds sufficient releasable curtailment, consults the present weather forecast, determines that with high probability sufficient power will be available, then completes the contract (including price) with the customer.
5. The grid operator (perhaps with some delay) directs the solar farm to release (de-curtail) an appropriate amount power, while at the same time directs the customer's car to begin accepting electric power at a rate that balances the de-curtailment.
6. The grid operator monitors the charging until it is complete, then disconnects the car from the grid, and re-curtails the solar farm the appropriate amount.

Figure 7: A use case for variable supply service.

Even with such important details as pricing, compensation, and demand excluded (for now), at least two important advantages of the setup are immediately apparent. First, in constructing the base planning curve (and operating roughly as above), the utility company reduces its risk from solar variability. Knowing that the curve will be supplied, even with just high probability, enables the utility better to configure the grid in the face of anticipated demand. Second, to the extent that what would otherwise be guaranteed demand is met by the new variable supply market, demand variability in the guaranteed supply market can be expected to be reduced. This would, of course be abetted by real time pricing in the conventional real time supply market.

The setup requires a great deal of investigation before anything like this setup can be judged to be proved out. That is well beyond the scope of this paper (or any single paper). In the next section, we foray an initial confrontation with the data, using a representative albeit limited set.

5 Fitting a Plan

We focus on hour 12 insolation data for Philadelphia for the years 2005, 2010, and 2015. We created a base planning curve using a robust nonparametric curve fitting method on the hourly means from the three years (MATLAB's `smooth` function applied using robust loess, `'rloess'`).

Figure 8 plots the three data years, showing insolation compared to the base planning curve using all three years. What we saw earlier with data summaries is vividly apparent in the figure: 2015 was an unusually good year (compared to 2005 and 2010) for insolation. In consequence, the fit of the base planning curve during the individual years leaves much variance from the realized data.

Figure 9 adds +10% and -10% bands to the base planning curve of Figure 8. It also plots the hourly realized insolation values as unconnected dots, the better to see their distributions. As is evident from the plots, a 10% default curtailment rate would do well during 2015 in reducing the need for power provision to meet the base planning curve, but during 2005 and 2010 there would be many times when this is insufficient.

Figure 10 retains the +10% band of Figure 9 but drops the -10% band in favor of a -50% band. We see that even here there is considerable underproduction in 2005 and 2010.

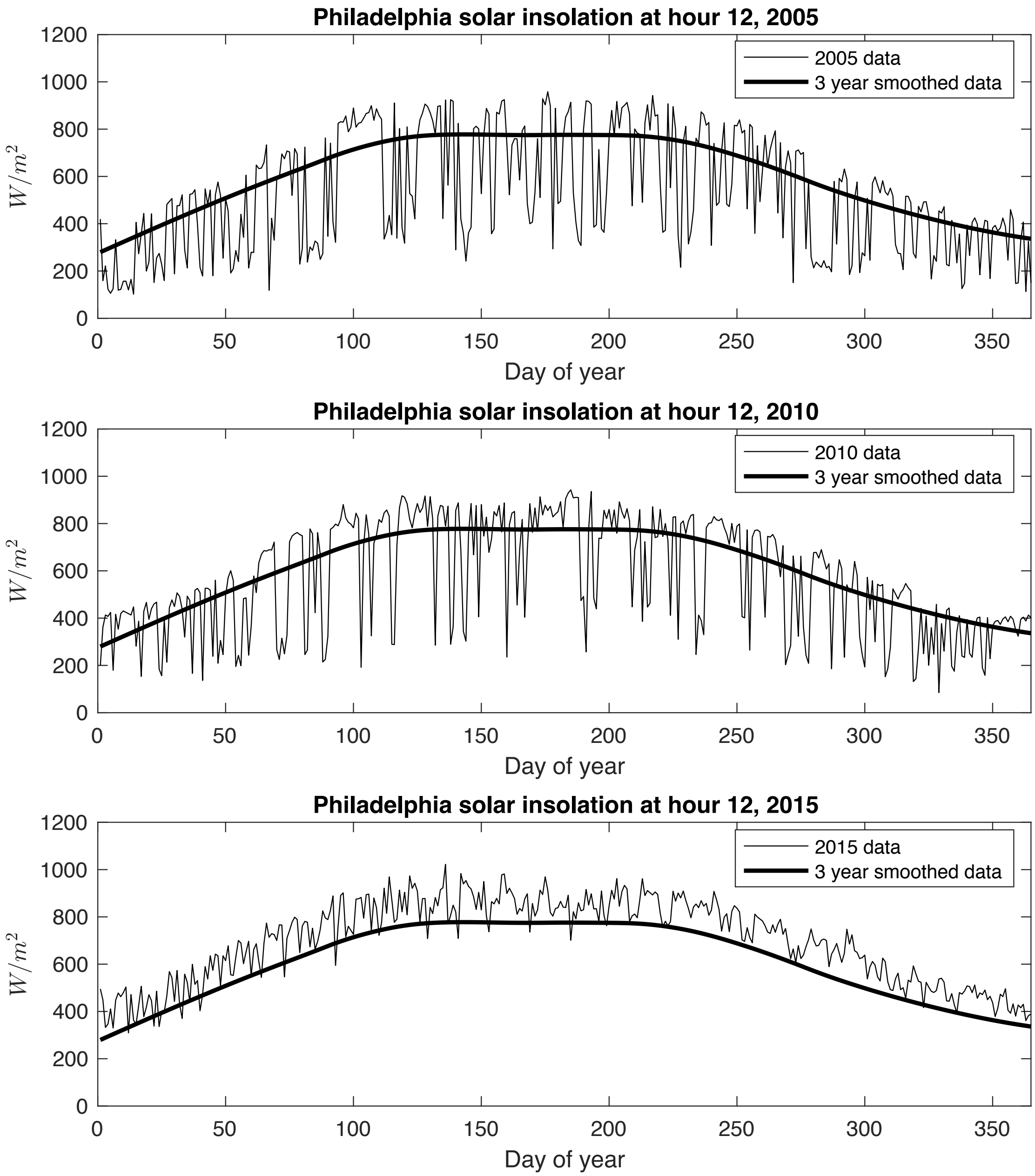

Figure 8: Three years of Philadelphia noon insolation compared to a three year smoothing.

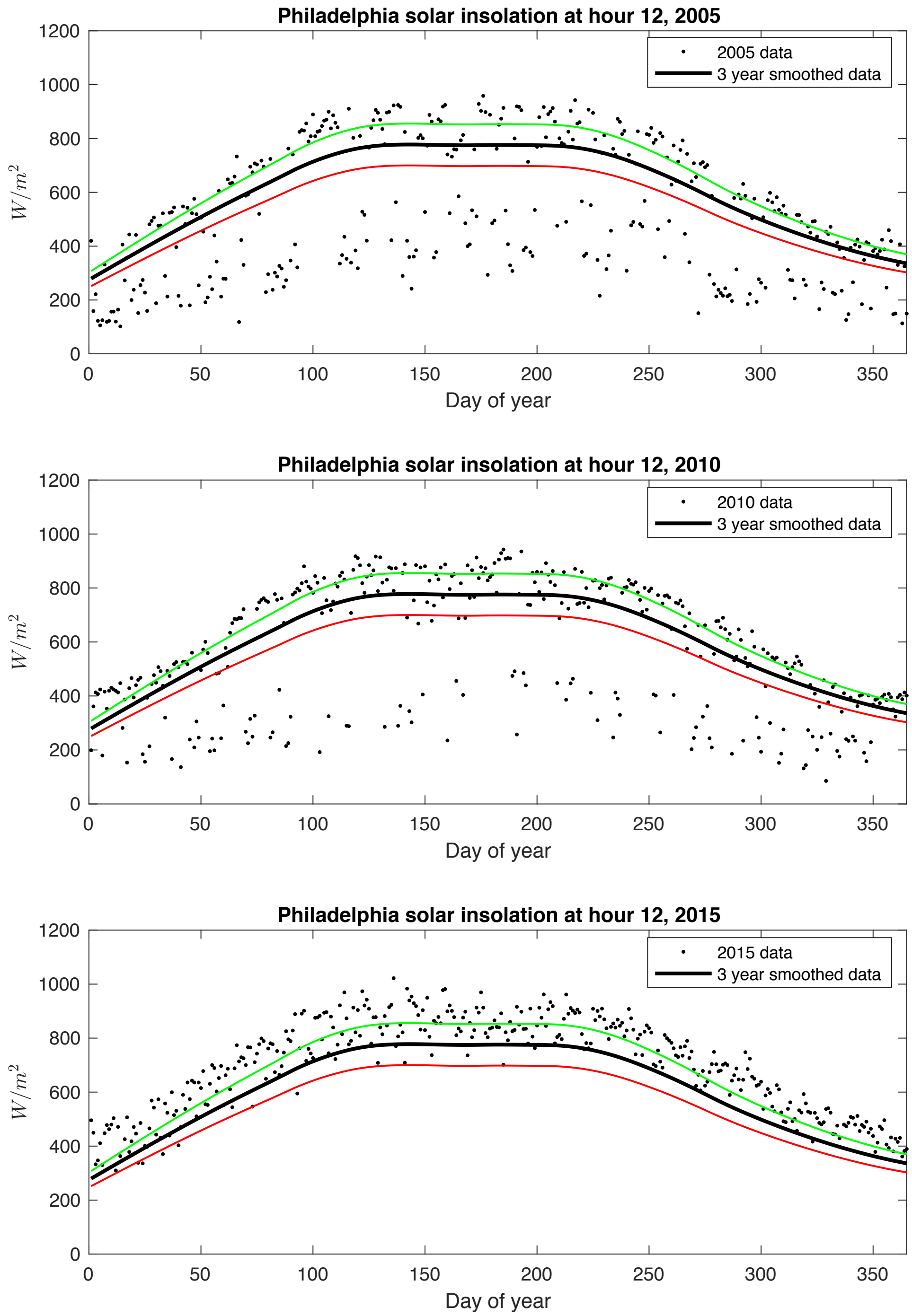

Figure 9: Three years of Philadelphia noon insolation compared to a three year smoothing (black), smoothing + 10 percent (green), and smoothing - 10 percent (red).

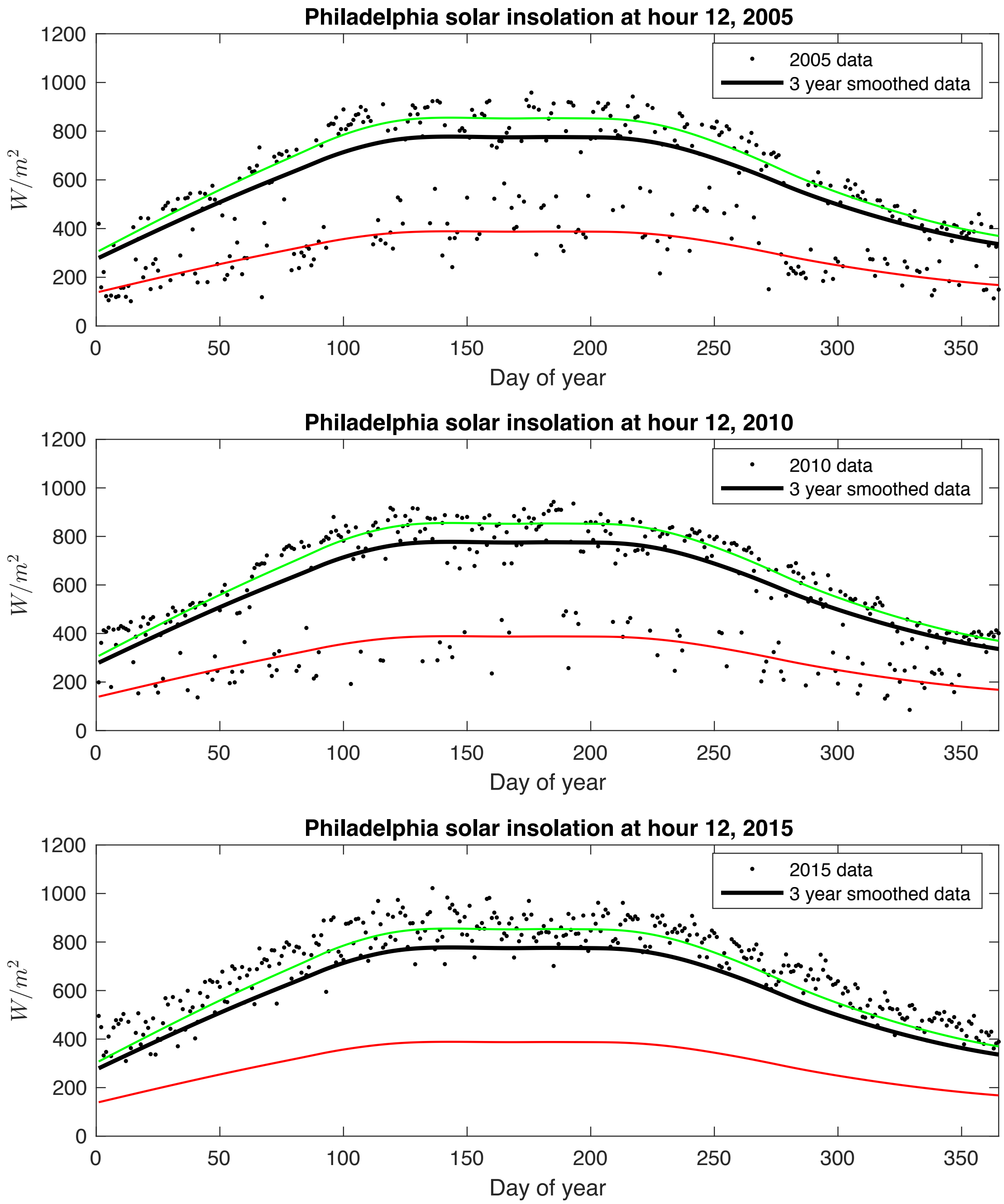

Figure 10: Three years of Philadelphia noon insolation compared to a three year smoothing (black), smoothing + 10 percent (green), and smoothing - 50 percent (red).

At this point tabular data may be more apt. Table 1 shows that we get a substantial improvement in the number of days with underproduction (at hour 12) if we use a default curtailment rate of 10%. Increasing this yields only incremental improvements until we reach 40 or 50% and even then there are scores of days in 2005 and 2010 that have underproduction.

Discount	2005	2010	2015
0%	180	137	22
10%	156	106	5
20%	151	94	0
30%	141	92	0
40%	111	74	0
50%	81	53	0

Table 1: Days per year in which curtailment at the discount level fails to cover underage of insolation compared to plan, during the noon hour.

Table 2 expresses the underproduction not as days as in Table 1, but as kilowatt hours of underproduction per square meter of solar PV panels. The numerical patterns broadly parallel those in Table 1.

Discount	2005	2010	2015
0%	63.1549	52.1939	12.2454
10%	48.1849	32.6350	2.0421
20%	45.8064	26.1463	0
30%	41.4079	25.6276	0
40%	28.8902	19.5107	0
50%	19.4035	12.1824	0

Table 2: Kilowatt hours per year of underage per square meter on solar PV when curtailment at the discount level fails to cover underage of insolation compared to plan, during the noon hour.

Finally, Table 3 is like Table 2 but reports surplus in kilowatt hours per square meter of solar PV panel. This surplus under our setup would be available to the variable demand market. Note: (1) Comparing Table 3 to Table 2, the surplus for the year always substantially exceeds the shortage. This opens a path to optimization, which can be addressed in future research. (2) Substantial annual variation is very much in evidence. This is unlikely to be a problem solvable by storage, as it is unlikely that annual demand can be made to fluctuate in lock step with annual weather patterns. (Although, reduced insolation may reduce demand for air conditioning.)

Discount	2005	2010	2015
0%	129.5813	155.9810	242.0905
10%	144.5513	175.5399	252.2938
20%	146.9298	182.0286	254.3359
30%	151.3283	182.5473	254.3359
40%	163.8460	188.6642	254.3359
50%	173.3327	195.9925	254.3359

Table 3: Kilowatt hours per year of overage per square meter on solar PV when curtailment at the discount level covers any underage of insolation compared to plan, during the noon hour.

6 Discussion

A number of insights can be gleaned from this exercise, with the caveat, of course, that very much more data, including remaining hours of the day and other locations, will need to be examined before any very firm conclusions can be drawn.[1] We note the following in particular:

1. The two ideas at the core of our proposed setup—dispatchable solar and creation of a variable supply market for electric power—have some *prima facie* credibility. The cost of making solar dispatchable (to a degree) is modest, involving only wiring, switching, and control. This cost has already been met in the wind power sector. Moreover, there would be evident benefits for grid stability in making use of dispatchable solar. Dispatchable solar would fit well with a market, as sketched, for variable supply, especially if linked to reliable forecasts. We could expect that a flourishing

[1] We have done an initial examination of corresponding data for Harrisburg and Doylestown, two municipalities in the Philadelphia region. We get broadly similar results and do find a modest buffering or smoothing effect by combining data from the three sources. This could be effected in practice by distributing the solar PV resources among the three locations.

such market would contribute to stabilizing demand for the conventional, guaranteed supply market.

We note in this regard that our proposal should be framed as in the context of "reverse demand response" schemes, which have been proposed by others and are under active investigation (e.g., (St. John, 2016)). Part of what is new here (to our knowledge) is the linking of such a proposal to a specific regime and particular source of power (Philadelphia insolation).veat

2. The problem of annual variation remains very challenging. The idea is often expressed that cheap and ample storage would obviate intermittency issues associated with renewables, e.g., (Fox-Penner, 2014). While correct in principle, the prospect of using storage as a buffer for multi-year droughts should give us pause. Very likely we need to reconcile ourselves to a certain amount of what would be overbuilding for normal years. How might we exploit this adventitious excess production?

The explorations in this exercise serve to suggest a number of avenues for future research (besides expanding the scope of the data), especially these:

1. Assessing the potential and characteristics of a possible variable supply market for electric power. If a very large portion of demand could be met on a variable supply market sourced by solar PV and other renewables, this would go a very long way towards solving the intermittency problem. The question, then, is what that portion is or is likely to be. We note that any electric power application with storage (electric cars were our example above) is potentially a candidate for a variable supply market. In addition, many applications if powered by DC (direct current) have demands flexible enough to be considered for variable supply. An example currently in place is using standalone solar power to drive irrigation pumps. The DC pumps run when power is available and work with fluctuating amounts of power. This can be conceptualized as exploitation of another form of storage: the earth holding water for release at a later time. Thermal reservoirs (e.g., water heated or cooled for later use in temperature regulation in buildings), which can be heated or cooled more or less at arbitrary times, are a very promising category falling under this conceptualization. Very possibly, the practical scope for variable supply is indeed quite large.

2. As noted above, our proposed setup can be combined with many other configurations and ideas. Exploring them, assessing them carefully, is an important task for future research. Including wind power in the variable supply market and in the curtailment with a base planning curve is surely a very high priority, as is exploring demand response regimes tailored to the intermittency patterns of insolation.

3. A number of studies have found diversification, both geographic and modal (wind, solar, etc.) to be effective and cost-efficient in supplying power and stabilizing the

grid, e.g., (MacDonald et al., 2016). This, of course, comes with the cost of high voltage, long distance transmission lines. We are intrigued by our initial findings, indicated above, that a degree of smoothing or buffering is achieved with only the modest diversification of solar PV in two cites within 160 kilometers of each other. How much can be achieved this way by linking sources to already existing regional grids?

4. Besides expanding the scope of analysis with additional weather data, it will be important to include demand data. We note that there is generally a positive correlation between insolation and demand for power. This suggests that the grid operator could absorb much of the variable supply production indicated in Table 3.

5. We have said little about costs, other than indicating that solar PV is cheap vis à vis LCOE and that the setup costs (curtailment, control) are likely to be modest. This lacuna will need to be addressed in future research. We do note the following: (i) total system cost, rather than LCOE is the proper measure of the cost of a generation method. Let us provisionally think of this as LCOE + variability mitigation cost, where the latter includes accommodating variable demand, variable supply, and availability (fossil fuel plants have to be taken off line periodically for maintenance); (ii) Given that variability mitigation costs are already substantial with conventional systems and that LCOE for solar is comparatively low, careful investigation will be needed to find a fair comparison and it is not obvious at this point what the outcome will be. We are pleased to have presented a new contender and are eager to pursue the investigation to resolution.

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