# Long-Distance Interconnection as Solar Resource Intermittency Solution: Optimizing the Use of Energy Storage and the Geographic Dispersion + Interconnection of Solar Generating Facilities.

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*Abstract* **— As governments worldwide look to increase the capacity of PV and other variable generation sources in their generation portfolios, dealing with resource intermittency begins to take center stage in the debate over how to achieve ambitious renewable energy targets.**

**Variability of the solar resource occurs across many different temporal scales: from cloud-driven variability on the order of seconds to seasonal variability driven by the Earth's sidereal orbit and axial tilt. We develop herein a model to investigate the impacts and technological solutions to variability at the temporal scale of greater than one day—variability linked to the passage of seasons and regional-scale meteorological phenomena.**

**We investigate two supply-side technology and planning-driven techniques to mitigate the impacts of stochastic and deterministic resource intermittency: Bulk electrical energy storage and Long-distance interconnection coupled with geographic dispersion of solar generating facilities.**

**A quantitative analytical framework has been developed in the context of this research by which to weigh the environmental and economic tradeoffs between these two approaches for a given geographic region. We use 24 years of globally distributed, daily-averaged, satellite-derived irradiances derived from the International Satellite Cloud Climatology Project (ISCCP) via NASA's Surface Meteorology and Solar Energy (SSE) database to model time/site-specific photovoltaic production across the globe at the time scales of one day or more.**

**Within this paper, we discuss the model's operation, apply it to a region spanning the European/MENA region, centered in Madrid and provide a discussion of the results, including an economic optimization of the interconnection/storage solution needed to alleviate intermittency and serve predetermined load requirements.**

***Index Terms*** **— Energy Storage, variability, intermittency, optimization**

## I. Introduction

**Widespread high-penetration integration of photovoltaics into electrical grids across the world is faced with a developmental hurdle due to the temporally and spatially variable nature of the solar resource. Critical to the sustained growth of the industry and the collective benefit of humanity we stand to gain from a world powered by solar energy is a deep understanding of the costs we face in dealing with this resource intermittency.**

Unless this intermittency issue is addressed, the majority of electrical grids will begin to experience reliability issues after PV capacity penetration reaches 20% of peak grid capacity. As an illustrative example, by the second quarter of 2012, the German state achieved a PV energy penetration of 5.3% (equivalent to a ~26.5% capacity penetration.) Correspondingly, on a very sunny day in May of the same year with rather low relative demand; solar PV supplied 50% of the country's demand. [1] Critics in Germany and elsewhere cite several issues with the PV paradigm at this level of penetration, including effects on grid frequency, voltage, costs of back-up generation and congestion across the existing electrical grid network. [2]

The effects referenced above are largely due to a spatial and temporal de-coupling between supply and demand. Although some of the grid demand peaks may coincide quite well with high solar resource, at other times supply and demand can be at entirely different levels leading to increased costs to the consumer. [3]

While Germany and other countries push towards ever higher penetrations of renewable electricity, the need for minimization of intermittency becomes ever more important. In this paper, we examine how the net LCSE (Levelized Cost of Solar Electricity) necessary to provide 100% of a location's electricity—without creating an overcapacity—changes when PV is distributed and interconnected over an increasing radius around the load (up to a distance of 5000km.) The LCSE is a function of the cost of the PV, the cost of the storage necessary and the cost of the transmission lines needed for interconnection. For the purposes of this paper, we describe the model's operation and results for a load centered in Madrid, Spain.

Addressing the problem of intermittency head-on and developing appropriate solutions could do a lot to reverse perceptions that PV will cause a widespread disruption of the electrical grid as some utility operators fear. It is the aim of this paper to detail a computational model that is being developed to examine and compare the costs of creative multi-pronged supply-side solutions to this issue.

## II. Methodology

The central aim in developing this model was to create a tool, which would be able to analyze the cost tradeoffs between storage and interconnection at high penetrations of

PV. We chose to pursue the model development by analyzing a rather simple scenario and asked ourselves the following questions:

- If our entire demand is centralized at a single point, what is the cost of storage necessary to meet 100% of this demand with Solar PV co-located at the demand site?
- If the radius around this central point is increased, the same capacity of PV is distributed across this area and interconnected to the centralized demand site, by how much do the costs of required storage to meet 100% of this demand decrease?
- Does the marginal increase in LCSE due to the distribution and interconnection of PV across the expanded region outweigh the decrease in the marginal LCSE due to the decrease in the cost of storage?

*A. Stochastic vs. Deterministic Variability and Demand*

There are two primary categories of intermittency present in the solar resource. One is stochastic, or largely unpredictable, and is derived from the synoptic movement of weather fronts, the eruption of volcanoes, and the passing of clouds. The other type is deterministic (thus predictable) and derives from the sidereal movement of the earth around the sun (combined with the earth's axial tilt) and the diurnal rotation of the earth about its axis.

With this in mind, we develop two 'extreme' scenarios to compare how the costs of storage + interconnection change whether they are helping resolve the intermittency caused by predictable or unpredictable variation in the solar resource.

$$365L - \sum_{i=1}^{365}\left(P_i - \ell_i\right) = 0 \tag{1}$$

In our first scenario, in order to measure the costs of a combined storage and interconnection solution needed to overcome all variability (both deterministic and stochastic), we calculate the costs of storage and interconnection needed to meet a *completely flat load*. The capacity level of this flat load to be met (L) is calculated such that the net demand over a given year equals the sum of the PV electricity generated over the same time period ($P_i$) less the losses incurred through storage and electrical transmission ($\ell_i$.)

With a PV capacity factor of ~20%, this means that PV capacity is ~5x higher than this flat demand capacity.

Reflecting on the costs of stochastic intermittency, our second scenario examines the cost of a storage and interconnection solution needed to meet a seasonally varying load. The seasonally varying load we define based on the profile of a 30-day moving average (symmetrical about the day in question) of the 10-year daily average solar radiation, R*i,j.

$$\frac{1}{30}\sum_{j-15}^{j+15}\left[\frac{1}{10}\sum_{i=1}^{10}R_{i,j}\right] = R^*_{i,j} \tag{2}$$

In the equation above, the i- indices represent the year number in the 10-year study period and the j – indices represent the day number. This profile is then shifted so that as in the first scenario, the sum of electricity generated by the PV over a given year (less transmission and storage losses) is equal to the sum of the demand over that same period.

Storage losses in either scenario cannot be determined before this load threshold is fixed, and in turn, the profile of the load threshold is dependent on these loss values. Thus, a Newtonian optimization is performed to quantify the amount (S) by which the load profiles ($L_i$) need to be shifted so that they satisfy the equality:

$$\left[\sum_{i=1}^{365}\left(L_i\right) + S\right] - \sum_{i=1}^{365}\left(P_i - \ell_i\right) = 0 \tag{3}$$

To be noted is that within the context of both scenarios, we use daily-averaged solar radiation data. Thus, we are examining the total costs of intermittency on the timescale of 1 day or above. In addition, we ignore the (small) effect of inter-annual solar resource variability by allowing the load threshold (either flat or seasonally-variable) to scale each year in order to satisfy the equality in equation 3.

*B. Solar Radiation and PV Production Simulation*

Measuring accurately the cost tradeoffs between interconnection and storage in combination with large penetrations of PV required the creation of a model with high quality and geographically comprehensive solar resource data. Thus, as an input, our model uses 30 years of globally-distributed, daily-averaged, satellite-derived surface and top-of-atmosphere shortwave downward radiative flux from the International Satellite Cloud Climatology Project (ISCCP) via the Surface Meteorology and Solar Energy (SSE) database at NASA Langley Research Center's Atmospheric Science Data Center (ASDC.)[4]

Simulating PV generation at any of the locations within a given radius around our centralized demand center required the derivation of solar radiation in the plane of a typical PV array each of the geographical points of interest in our database. Using an anisotropic tilted-plane solar radiation model, we have developed a database of global and beam daily-interval timeseries at latitude tilt, latitude tilt + 15°, latitude tilt - 15° and one-axis tracking for every latitude and longitude coordinate on the planet between 60°N and 60°S. [5,10,12]

In the context of this paper, we exclusively use the derived radiation at latitude tilt. From these data, we are able to accurately simulate PV production at ideal tilt (the tilt at which installers would position their arrays to achieve maximum annual solar gain.)

$$P_i = S_i \times C_{PV} \times \varepsilon_{DC/AC} \tag{4}$$

Our model calculates the PV generation from solar radiation by specifying the PV capacity (CPV) and the DC/AC conversion efficiency or de-rate factor ( $\varepsilon$ DC/AC).

The number of sun-hours for the given day $S_i$, are in our case derived from daily average solar radiation data by multiplying by a conversion factor of $2.4\times10^{-2}$ .

For the purposes of this paper, we use a PV capacity of 10 GW and an $\varepsilon$ DC/AC of 95%.

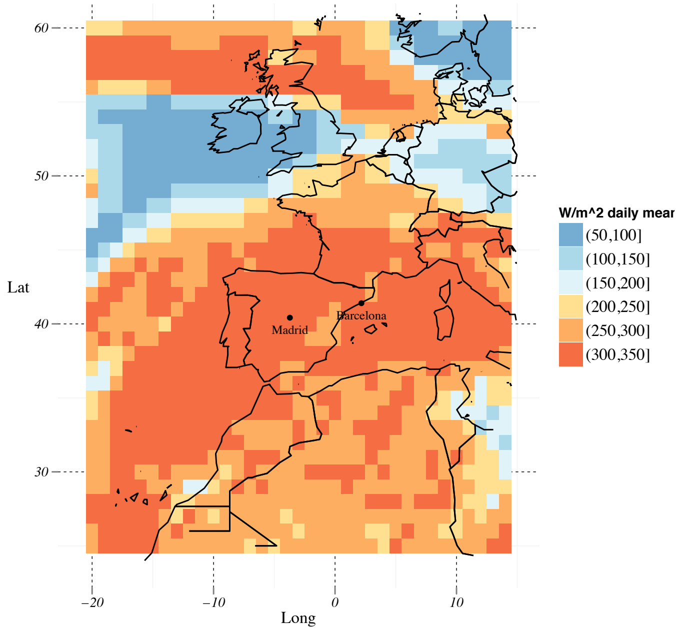


Figure 1: Global solar radiation at latitude tilt for the area surrounding Madrid, Spain on 17th June, 1998 derived from the NASA-SSE ISCCP dataset.

When we distribute PV across a region in our model, we distribute by equivalent capacity. For example, if we have 51 geographic points in a region defined by a 400 km radius around the central load site and a PV capacity of 10 GW, we will have 51 PV generating facilities of 196 MW each.

The capital expenditures (CapEx) for PV used in this iteration of the model are set at \$2/Wp installed cost with operation and maintenance costs (O&M) set at 0.01% of CapEx per year. Although these numbers are reasonable estimates for large scale PV globally in 2012 according to SolarBuzz, the values are easily changeable by the user.[6]

### *C. Physical Electrical Interconnection Model and Costs*

The electrical interconnection model seeks to interconnect all solar generating facilities within a given radius to the central point where the load is located for the lowest possible cost. In order to do this, we use Prim's algorithm to calculate a Euclidian minimum (cost) spanning tree (MST) interconnecting all of the solar generating facilities and the central load. [7, 8]

To construct a MST with Prim's algorithm, every possible connection (also known as edges) between every solar generating facility (also known as nodes) must be weighted according to their favorability (or costliness.)

Before the MST grid is drawn, the true cost of the interconnections cannot be known. This is due to the fact that part of the cost is a function of cable capacity and cable capacity is in turn a function of how many PV generating facilities are connected to it upstream from the central load point. Thus, our edge-weighting matrix uses the geographical distance (in km) between two nodes multiplied by the geographical distance of the center of the link to the central load point as a proxy for cost before it is calculated.

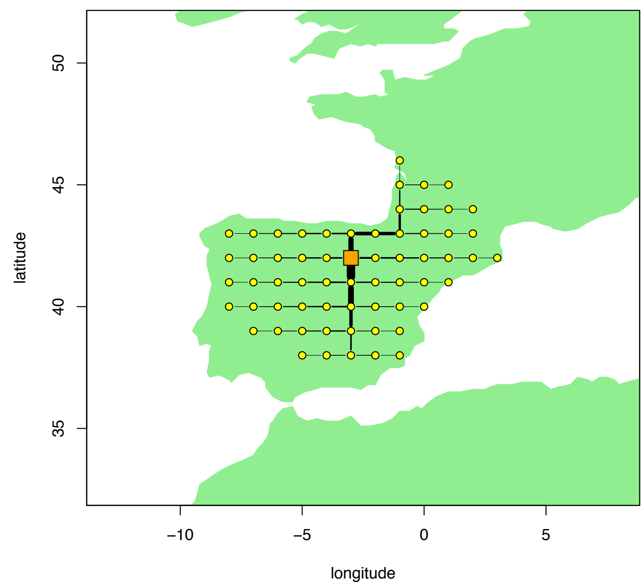


Figure 2: HVDC MST interconnecting solar generating facilities across 400km – radius around Madrid, Spain

This way, longer connections are disfavored by the algorithm, as are connections that connect from the central point to some point at the extremity of the region without connecting to other points on the way. Additionally, the algorithm is told to avoid placing solar generating facilities over water and above 60°N (approaching the arctic circle.)

The result is a plot like the one shown above, which graphically displays an MST interconnecting all solar generating facilities within a 400km radius around Madrid, Spain. The weights on the interconnection lines are relative to their capacity, which is determined by the maximum capacity of all solar generating facilities upstream from the central load center (orange square.)

In the current model iteration, the links are HVDC and their costs are assumed to be a linear function of length and capacity. The model is flexible enough for a user to specify any cost they feel is appropriate but for this paper, we have borrowed data from ABB which puts the cost of an 800kV bipole HVDC at \$327.66/MW/km.[9] We set the HVDC

O&M for this iteration of the model at 0.5% of CapEx, annually and the loss at 3.65%/1000km (even though this is the stated loss at full load.) Loss is applied to each node based on its shortest-path distance

*D. Storage Sizing and Economic Costs*

The cost of energy storage needed to meet a given load type (either flat or seasonally varying), is calculated by first determining the required power capacity (MW) and required energy capacity (MWh) of said storage. Power capacity of the energy storage is determined by subtracting the power generated time-series from the load, thereby giving the load flow into (positive sign) or out of (negative sign) of the storage. The maximum flow into or out of the storage determines the required power capacity. For example, if the maximum power flow occurs when the net PV generated ($G_{PV,i}$) across the region is 10 GW and the load ($L_i$) to be served at that time is 5 GW then the required storage size ($C_{P,St}$) is set as the 5 GW surplus.

$$C_{P,St} = MAX\left|L_i - G_{PV,i}\right| \tag{4}$$

Energetic cost of energy storage is calculated first by taking the rolling sum of the power flow ($C_{P,St}$) defined above in (4.)

$$C_{En,St} = MAX\left[\sum_{1}^{i}\left(L_i - G_{PV,i}\right), \forall\left\{1 \le i \le N\right\}\right] + \left|MIN\left[\sum_{1}^{i}\left(L_i - G_{PV,i}\right), \forall\left\{1 \le i \le N\right\}\right]\right| \tag{5}$$

If we shift this series by the rolling sum's minimum, then it represents the cumulative amount of energy held within the storage at any given time. The maximum loading defines the energy storage capacity ($C_{En,St}$) required to meet the load.

The economic costs associated with the power and energy capacity of storage are a parameter that can be manipulated by the model's user. In the model run used in this paper, we have used an energy storage power capacity cost of \$1300/kW, an energy capacity cost of \$67.5/kWh, an O&M of 0.5%/annum on CapEx, and a round-trip efficiency of 80%; values which are roughly coincident with reported costs for pumped hydroelectric storage. [14] The reason we use this type of (bulk) storage is because we need to store energy for long durations (up to half a year) to overcome the seasonal intermittency inherent in the solar resource and meet a flat load.

*E. Levelized Economic and Environmental Costs*

In this early iteration of the model, we model environmental costs based on the MWh-e storage capacity determined through equation 5. Although the model is flexible enough to take any values as input, we have used 35.7 T $CO_2$-e/MWh of storage capacity for construction and 1.8 T $CO_2$-e/GWh representing the global warming impact of O&M, numbers coincident with Pumped Storage Hydroelectric storage. [11]

$$LCSE = \frac{\sum_{i=1}^{n} \frac{\chi_{cap,i} + \chi_{maint,i}}{\left(1+r\right)^{\frac{i}{365}}}}{\sum_{i=1}^{n} \frac{P_{PV,i}}{\left(1+r\right)^{\frac{i}{365}}}} \tag{6}$$

Our Levelized Cost of Solar Electricity (LCSE) is calculated based on the above formula, a function of the total capital ($X_{cap,i}$) and maintenance ($X_{maint,i}$) expenditures in each year (i) of the analysis (for the interconnection, PV and storage), the discount rate, r, the lifetime of the system (n) and PV production ($P_{PV,i}$) with round trip storage efficiency and transmission losses included.

When considering the Levelized *Environmental* Cost of Solar Electricity for the combined storage, PV and interconnection solution, we replace the annual economic maintenance and capital costs with their environmental corollaries referenced above.

## III. Results

As the 10GW of PV is gradually spread across larger and larger radii around Madrid, the effect of geographic smoothing becomes apparent on the time-series. In the plot below, we show the timeseries for a single year at a single point (Madrid, solid black line) and how it is smoothed across a 5000 km radius in steps of 500km. As the radius is expanded, the line's saturation is increased until it becomes the deep red color.

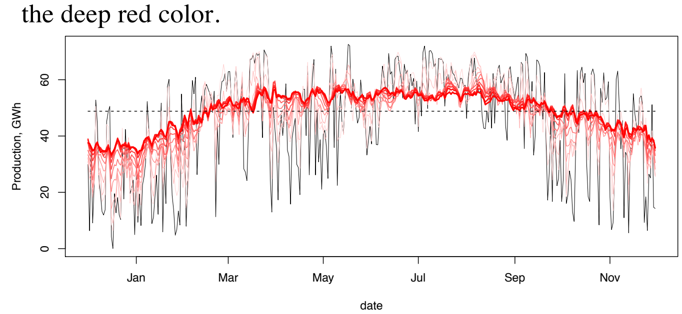


Figure 3: Timeseries of PV production when solar generating facilities are spread out across increasing radii around Madrid, Spain.

Furthermore, the two dotted lines represent, respectively, the flat load (horizontal at ~49 GWh/day) and seasonal load—whose shape derives from the 30-day symmetrical moving average of the 10-year daily mean solar radiation.

*A. HVDC Grid Properties*

Because the marginal cost of the HVDC grid doesn't depend on whether the load being met is flat or variable, we treat the costing for the HVDC grid first. Physically, when we apply the MST model, what we see when we expand the grid across a 5000 km radius is an exponential decrease in the mean cable capacity of each link and a corresponding increase in total length of all interconnection cables with increasing radius.

The exponential decrease in mean cable capacity makes sense because as more solar generating facilities are added to an expanded region, each adds a link to the HVDC grid and as we are keeping the same capacity spread across the region at each radius, there is less and less capacity to carry per link. At a 5000 km interconnection radius around Madrid, the total length of all cables in the MST grid is 280,509 km while the mean link capacity is 152.2 MW.

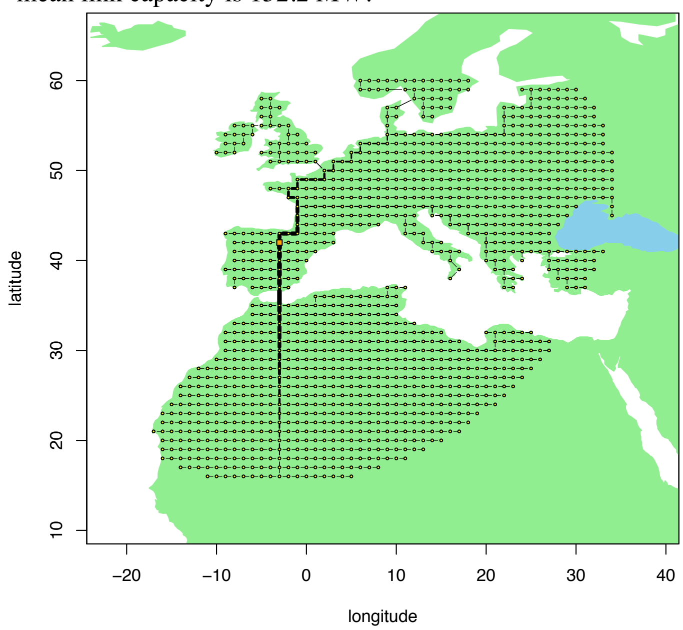


Figure 4: HVDC MST interconnecting solar generating facilities across a 3000km – radius around Madrid, Spain (with a limit at 60°N)

*B. Storage Capacity Required*

As expected, the amount of storage capacity required to meet 100% of load differs greatly in magnitude whether the load is flat or seasonally variable. However, in each case, the amount of required storage capacity decreases exponentially with increasing radius.

By expanding across a 5000 km radius, the amount of required storage power capacity to meet a flat load is reduced by 66% versus a single point from 9.9GW to 3.4GW. For the same flat load, the storage energy capacity required is reduced by 60% versus a single point from 3,029GWh to 1,211GWh. This can be thought of as the reduction in the amount of storage required to eliminate *all* variability in the solar resource, both predictable and random.

By contrast, the amount of storage *power* capacity required to meet a variable load—which we defined as representing storage necessary to overcome stochastic intermittency—is reduced by 86% when expanding the grid over 5000km from 10.3GW to 1.4GW. The amount of storage energy capacity required to meet this same variable load is reduced by 83% when expanding over the same region from 1,608GWh to 274GWh.

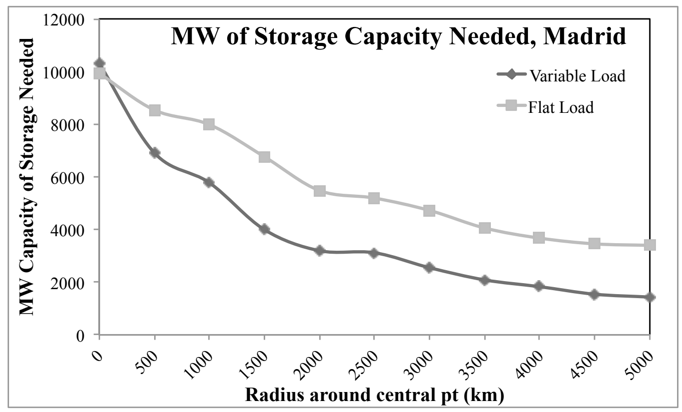


Figure 5: Power capacity of storage needed (MW) at each radius expansion around Madrid, Spain for meeting each load type.

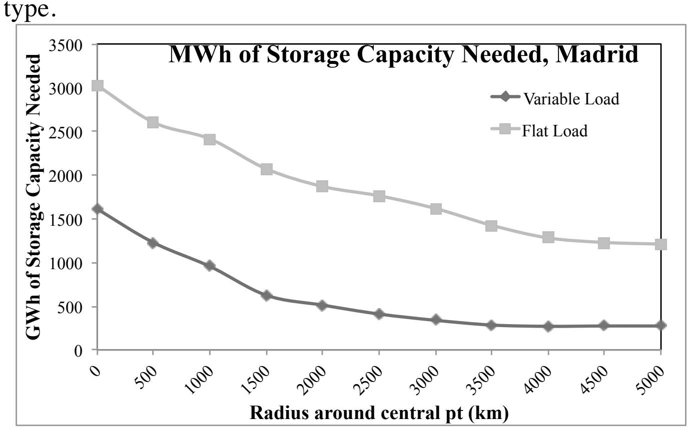


Figure 6: Energy capacity of storage needed (MWh) at each radius expansion around Madrid, Spain for meeting each load type.

*C. Economic Costs of Storage + Interconnection*

Corresponding to the relative amounts of storage energy and power capacity required to meet the two different load types, the marginal levelized cost of solar electricity (LCSE) also greatly differs depending on whether the load being met is flat or seasonally variable.

For no interconnection and all PV capacity and demand co-located, the net levelized cost of electricity (LCOE) of PV + storage necessary to meet a flat load is \$0.96/kWh whereas it is only $0.56/kWh to meet a variable load. In other words, the marginal levelized cost of the storage is reduced by 41% merely by not worrying about the deterministic—predictable—portion of solar variability. Note that we use a discount rate of 5% and PV and storage lifetimes of 30 years to calculate the LCOE.

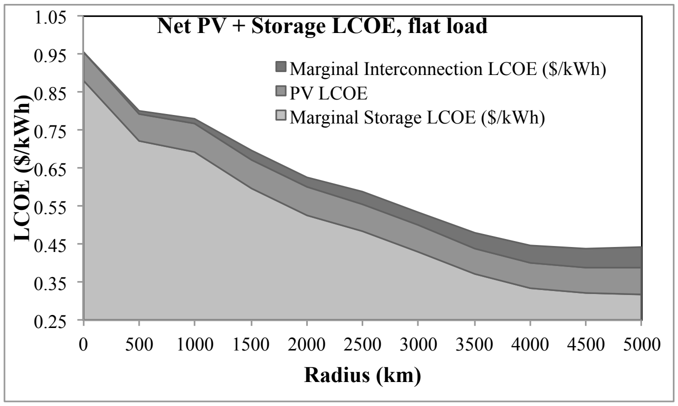


Figure 7: Total Levelized Cost of Electricity including storage, PV and HVDC interconnection for meeting a flat load profile as a function of radius around Madrid, Spain

When meeting a flat load, the net LCOE of PV, storage and interconnection comes to a minimum of $0.443/kWh at a radius of 5000km around Madrid—corresponding to a 53.7% reduction from the LCOE of PV + storage centralized at the site itself. The majority of this drop in LCOE is due to the drop in the marginal cost of storage, which falls from $0.88/kWh to $0.32/kWh.

When meeting a seasonally variable load, the LCOE of PV + storage + interconnection comes to a minimum of $0.197/kWh when PV is spread out across a 5000 km radius about Madrid, a cost 65.1% lower than when PV is co-located with demand. Most of this drop in cost comes from the 84.9% drop in the marginal cost of storage required to meet the variable load—from $0.49 /kWh to $0.074/kWh over the same radius.

In fact, the marginal cost of storage required to meet the seasonally variable load will likely continue decreasing well past the 5000km mark but it will be outpaced at some point by the increase in the marginal cost of interconnection as more distant solar generating facilities are added.

## IV. Discussion

It is interesting to note that the total cost of PV + storage + interconnection appears to stop decreasing as rapidly in the larger radii around Madrid. This is due to the continental geography of the Eurasian, African and North American Continent. Because we are expanding uniformly in all directions and the African continent becomes thinner as one travels south, a greater relative mass of solar generating facilities are being added to the North with each incremental radius. Thus, we are introducing seasonal variability into the solar radiation mix as fast or faster than we are reducing it by expanding southwards.

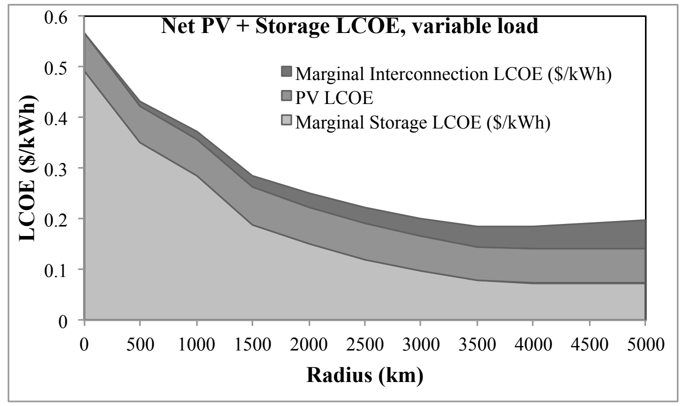


Figure 8: Total Levelized Cost of Electricity including storage, PV and HVDC interconnection for meeting a variable load profile as a function of radius around Madrid, Spain

The fact that more intermittency is being introduced by expanding the grid outwards radially in all directions (and that this increase in intermittency undermines the decrease in intermittency from geographic smoothing) underlines the need for a more intelligent PV dispersion algorithm. Future versions of this model will include a relative sizing optimization such that the PV capacity in sub-regional clusters will be manipulated such that their sum reduces the net variability across the region by the greatest amount possible.

## V. Conclusions

These results demonstrate that even in our theoretical case of a single centralized load, solar resource variability and the costs associated with it can be significantly reduced by interconnecting solar generating facilities over a large region. Our application of this model to a region spanning the North American continent with a center at Madrid, Spain showed that the marginal cost of electrical energy storage needed to compensate for 100% of the solar resource variability decreased by 63.9% when distributing and interconnecting PV across a 5000 km radius. This drop in the marginal cost of storage parallels the drop in net LCOE of PV + interconnection + storage of 44.3% over the same radius.
The marginal cost of electrical energy storage needed to compensate for only stochastic solar resource variability saw a maximum decrease of 84.5% when interconnecting PV over a 5000 km radius. Correspondingly, the net LCOE of PV + interconnection + storage drops by 65% over the same radius.

Meanwhile, in our model, even with a completely interconnected region of 5000 km in diameter, the marginal cost of HVDC interconnection needed to interconnect all of the distributed PV never exceeds 27.9% of total LCOE of PV + storage + interconnection.

While the centralized load and radially-distributed PV case we study here provides a glimpse into the reduction in economic costs we see from employing interconnection at the continental scale as another solution to solar resource intermittency, future iterations of the model will seek to add realism by adding more load centers with load profiles relative to their population and optimized regional sizing of the PV facilities to minimize the cost of storage by as much as possible.

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