OPTIMIZING THE MIX OF ENERGY STORAGE AND LONG-DISTANCE INTERCONNECTION AS SOLUTIONS TO SOLAR RESOURCE INTERMITTENCY AT HIGH PENETRATIONS OF PV ON THE GRID.

Marc J. R. Perez
CLCA, Columbia University
Center for Life Cycle Analysis
500 W. 120th St., #918 Mudd
New York, NY 10027
e-mail: mjp2167@columbia.edu

Vasilis M. Fthenakis
CLCA, Columbia University
Center for Life Cycle Analysis
500 W. 120th St., #918 Mudd
New York, NY 10027
e-mail: vmf5@columbia.edu

ABSTRACT

As the penetration of PV on electrical grids worldwide is increased, we approach a point where solar resource variability becomes an issue that needs addressing.

Solar resource variability occurs across a wide range of timescales: from intraday with the passage of clouds to seasonal with the rotation of the earth around the sun. We investigate in this paper the effects and solutions to 1-day or longer variability, variability linked to meteorological phenomena at the continental and seasonal spatiotemporal scales.

Two supply-side approaches to solving the problem of stochastic and deterministic resource variability these timescales are investigated: bulk energy storage and long distance interconnection with the geographic dispersion of solar generating facilities.

We have developed a quantitative analytical framework by which to weigh the environmental and economic tradeoffs between these two approaches for a given geographic region. We use 10 years of globally distributed, daily-averaged, satellite-derived surface and top-of-atmosphere shortwave downward radiative flux data from the International Satellite Cloud Climatology Project (ISCCP) via NASA's Surface Meteorology and Solar Energy (SSE) database to model photovoltaic production across the globe.

Herein, we discuss the model's operation, apply it to regions spanning the Western hemisphere and provide a discussion of the results.

1. INTRODUCTION

The obstacle posed by solar resource intermittency is perhaps the greatest barrier to its future widespread high-penetration integration into electrical grids across the world. Overcoming this barrier is therefore crucial to the sustained growth of the industry and the collective benefit of humanity.

Several reports cite that in most electrical grids, PV penetration above 20% of peak grid capacity starts to pose reliability issues unless the intermittency question is addressed. In the first half 2012, the German state hit 5.3% energy penetration of PV and on a single day in May of the same year, solar PV supplied 50% of the country's demand. (1) With this level of penetration, critics cite several issues with the PV paradigm, including effects on grid frequency, voltage, costs of back-up generation and congestion across the existing electrical grid network. (2)

These effects are largely due to a de-coupling between supply and demand both spatially and temporally. 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)

As Germany and other countries push towards even 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 4000km. 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 at Kansas City, MO.

2. METHODOLOGY

Our aim in creating 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 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 we increase our radius around this central point, distribute the same capacity of PV across this area and interconnect it to the centralized demand site, by how much do the costs of required storage to meet 100% of the 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?

2.1 Stochastic vs. Deterministic Variability and Demand

There are two primary categories of intermittency present in the solar resource. One can be said to be 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 daily synoptic 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.

$$365L - \sum_{i=1}^{365} P_i = 0 \tag{1}$$

In our first scenario, to measure the costs of storage + interconnection needed to overcome all variability (deterministic + stochastic), we calculate the costs of storage + 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 PV electricity generated (P_i) over the same time period. 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 storage + interconnection 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 scaled so that as in the first scenario, the sum of electricity generated by the PV over a given year is equal to the sum of the demand over that same period.

It is to be noted that in both scenarios, we use daily-averaged solar radiation data so 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 demand capacity (either flat or seasonally-variable) to change each year.

2.2 Solar Radiation and PV Production Simulation

To accurately measure the cost tradeoffs between interconnection and storage, we created a model which as an input, uses 10 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)

In order to simulate PV generation at any of the locations necessary around our central point, we first derive solar radiation at latitude tilt for each of the geographical points of interest in our database using an anisotropic tilted-plane solar radiation model. (5)

From these derived radiation 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.)

$$P_i = S_i \times C_{PV} \times \varepsilon_{DC/AC} \tag{3}$$

Our model calculates the PV generation from solar radiation by specifying the PV capacity (C_{PV}) 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 $2.4\times10^{-2}\ h\cdot m^2/W$.

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

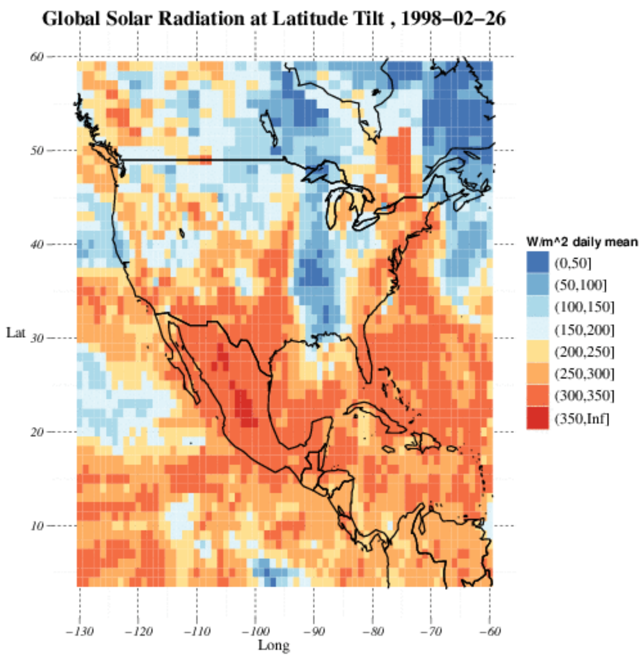

Figure 1: Global solar radiation at latitude tilt for the area surrounding Kansas City on 26th February, 1998 derived from the NASA-SSE ISCCP dataset.

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 $2/$W_p$ 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)

2.3 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, after several iterations, 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.

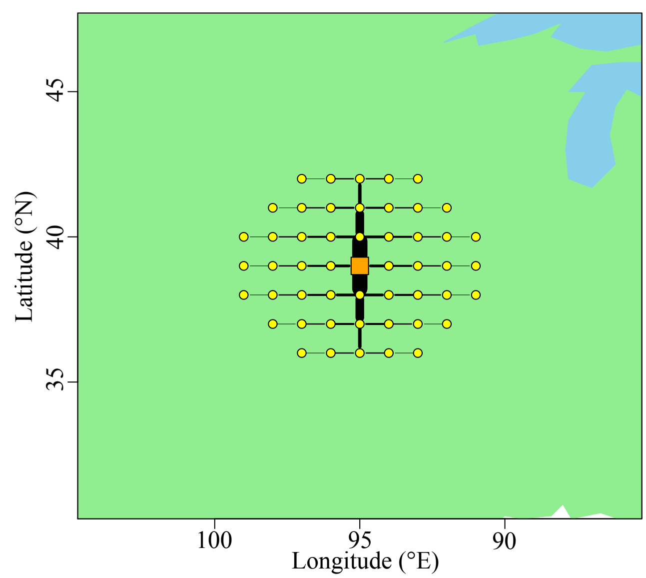

Figure 2: HVDC MST interconnecting solar generating facilities across 400km – radius around Kansas City, MO

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 Kansas City, MO. 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 chosen data from ABB which puts the cost of HVDC \$327.66/MW/km.(9) We set the HVDC O&M for this iteration of the model at 0.5% of CapEx, annually.

2.4 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.

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

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 and an energy capacity cost of \$67.5/kWh, and an O&M of 0.5%/annum on CapEx, values which are roughly coincident with reported costs for pumped hydroelectric storage. (10) 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.

3. RESULTS

As the 10GW of PV is gradually spread across larger and larger radii around Kansas City, 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 (Kansas City, solid black line) and how it is smoothed across a 4000 km radius in steps of 200km. As the radius is expanded, the line's saturation is increased until it becomes the deep red color. Furthermore, the two dotted lines represent, respectively, the flat load (horizontal at ~45 GWh/day) and seasonal load—whose shape derives from the 30-day symmetrical moving average of the 10-year daily mean solar radiation.

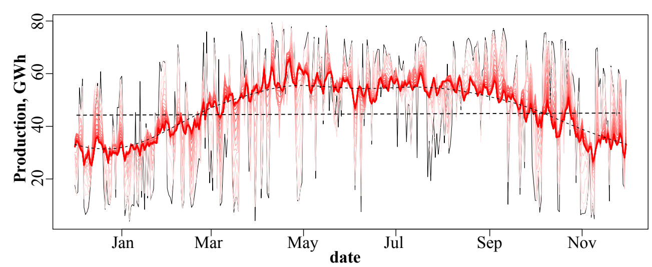

Figure 3: Timeseries of PV production when solar generating facilities are spread out across increasing radii around Kansas City, MO

3.1 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 4000 km radius is an exponential decrease in the mean cable capacity of each link and a logistic-curve-shaped 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. Part of the reason why the total length of all cables approaches a logistic-curve-style asymptote and stops increasing at the same rate around a radius of 2800 km is because we approach the boundary of the North American continent. Thus, for each additional increase in radius, less and less solar generating facilities are being added.

There is a noticeable small uptick in total cable length between 3800 and 4000 km radii because at this radius, the northern part of the South American continent begins to be interconnected.

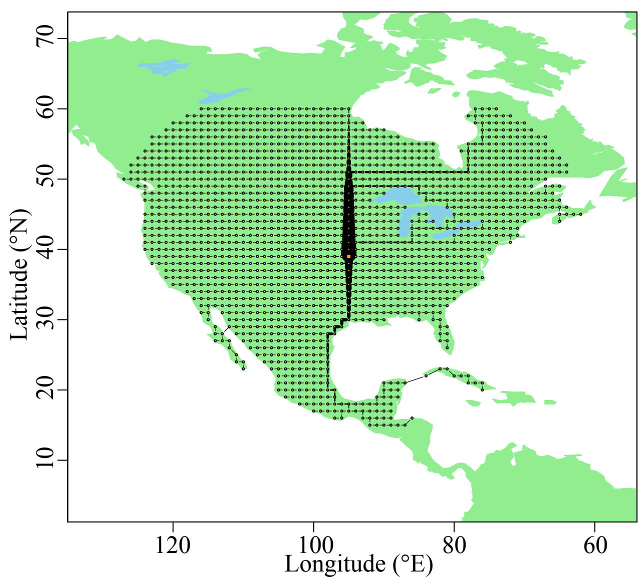

Figure 4: HVDC MST interconnecting solar generating facilities across a 3000km – radius around Kansas City, MO (with a limit at 60°N)

3.2 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 4000 km radius, the amount of required storage *power capacity* to meet a flat load is reduced by 51.5% versus a single point from 10.3GW to 5.0GW. For the same flat load, the storage *energy capacity* required is reduced by 34.3% versus a single point from 1610GWh to 1057Gwh. 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 76% when expanding the grid over 4000km from 11.0GW to 2.6GW. The amount of storage *energy capacity* required to meet this same variable load is reduced by 80.3% when expanding over the same region from 721GWh to 142GWh.

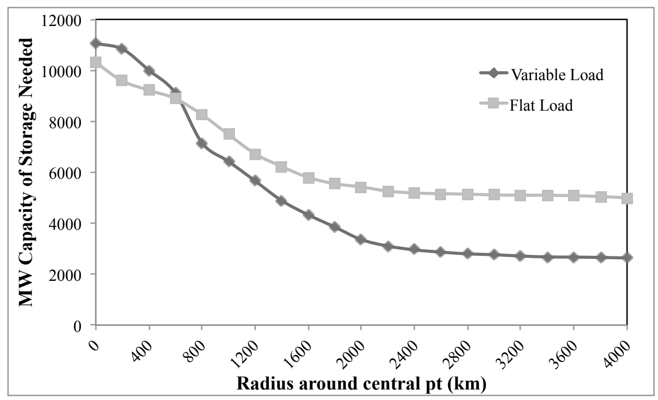

Figure 5: Power capacity of storage needed (MW) at each radius expansion around Kansas City, MO for meeting each load type.

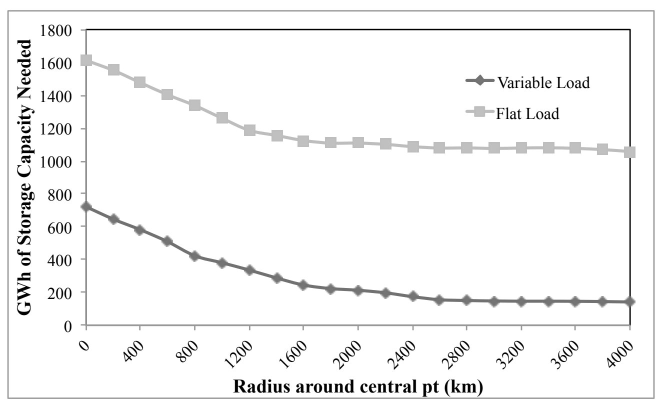

Figure 6: Energy capacity of storage needed (MWh) at each radius expansion around Kansas City, MO for meeting each load type.

3.3 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 $0.53/kWh whereas it is only $0.31/kWh to meet a variable load. In other words, the *marginal* levelized cost of the storage is reduced by 48.5% 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.

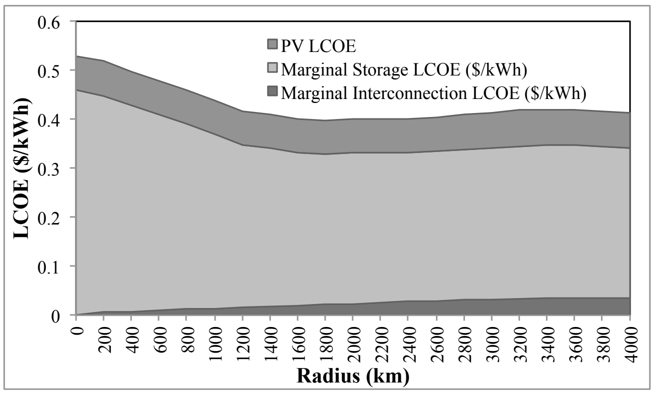

Figure 7: Total Levelized Cost of Electricity including storage, PV and HVDC interconnection for meeting a flat load profile as a function of radius around Kansas City, MO

When meeting a flat load, the net LCOE of PV, storage and interconnection comes to a minimum of $0.40/kWh at a radius of 1800km around Kansas City—corresponding to a 33% 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 $0.46/kWh to $0.30/kWh.

When meeting a seasonally variable load, the LCOE of PV + storage + interconnection comes to a minimum of $0.156/kWh when PV is spread out across a 2600 km radius about Kansas City, a cost 49.5% lower than when PV is co-located with demand. Most of this drop in cost comes from the 76.8% drop in the marginal cost of storage required to meet the variable load—from $0.24 /kWh to $0.06/kWh over the same radius.

In fact, the marginal cost of storage required to meet the seasonally variable load keeps decreasing well past the 2600km mark but it is outpaced at this point by the increase in the marginal cost of interconnection as more distant solar generating facilities are added.

4. DISCUSSION

It is interesting to note that after expanding past an 1800 km radius around Kansas City, the cost of storage needed in conjunction with PV to meet a flat load stops changing and even increases a bit. This is due to the geography of the American continent. Because we are expanding uniformly in all directions and the Gulf of Mexico sits directly South of Kansas City, past an 1800 km radius, most of the expansion of the grid occurs to the West/North West into Saskatchewan, Alberta, British Columbia and the American West. Because we are adding a greater mass of solar generating facilities to the North, we are introducing seasonal variability into the solar radiation mix as fast or faster than we are reducing it by expanding southwards. Because this load type is flat, the storage required to service it in conjunction with PV necessarily is sized to overcome the seasonal intermittency, while the storage needed to meet the seasonally variable load is sized to overcome stochastic intermittency.

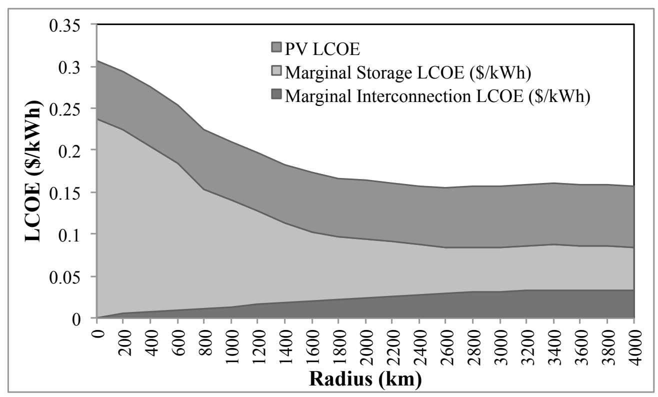

Figure 8: Total Levelized Cost of Electricity including storage, PV and HVDC interconnection for meeting a *variable* load profile as a function of radius around Kansas City, MO

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.

5. 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 Kansas City showed that the marginal cost of electrical energy storage needed to compensate for 100% of the solar resource variability decreased by 33% when distributing and interconnecting PV across an 1800 km radius. This drop in the marginal cost of storage parallels the drop in net LCOE of PV + interconnection + storage of 33% 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 76.8% when interconnecting PV over a 2600 km radius. Correspondingly, the net LCOE of PV + interconnection + storage drops by 49.5% over the same radius.

Meanwhile, in our model, even with a completely interconnected region of 4000 km in diameter, the marginal cost of HVDC interconnection needed to interconnect all of the distributed PV never exceeds 18% 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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